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BEFORE THE ARIZONA CORPORATION COMM

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744

Docket No. E-01345A-05-0816

Arizona Corporation Commission
DOCKETED
AUG 18 2006
DOCKETED BY NR

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Marylee Diaz Cortez, William A. Rigsby, Stephen G. Hill, David A. Schlissel and J. Richard Hornby in the above-referenced matter. Confidential material has been redacted from the testimony of Mr. Hill and Mr. Schlissel that is being filed with Docket Control. The confidential portions of their testimony are being lodged under seal with the Hearing Division, and are available to parties that have entered Protective Agreements with APS by contacting RUCO's counsel.

RESPECTFULLY SUBMITTED this 18th day of August, 2006.

Scott S. Wakefield
Chief Counsel

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of August, 2006 with:

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Ernestine Gamble
Secretary to Scott Wakefield

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's revenue requirement recommendation for APS based on my own analyses, as well as the analyses of other RUCO witnesses.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. I worked closely with RUCO consultants in formulating RUCO's position regarding the appropriate cost of service related to generation, and was responsible, along with RUCO witness William Rigsby, for reflecting the impact of those positions on APS' revenue requirements.

REVENUE REQUIREMENT

Q. Please summarize your recommended revenue requirements for APS.

A. RUCO recommends that APS' revenue requirement be increased by no more than $232.297 million, or 10.89%[1]. RUCO's recommended revenue requirements are summarized on Schedule MDC-1. RUCO's Original Cost, Fair Value, and Reconstruction Cost New Depreciation rate bases of $4,463.4 million, $7,728.2 million, and $6,095.8 million respectively are shown on Schedule MDC-2. The detail supporting the rate base is presented on Schedule MDC-3. RUCO's recommended adjusted operating income is presented on Schedule MDC-6. The detail supporting this recommendation is presented on Schedule MDC-7.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-12.

[1] RUCO's recommended increase is 4.44% net of the increase approved in Decision No. 68685.

SUMMARY OF ISSUES

Q. Please summarize the issues and recommendations you address in your testimony.

A. I address the following issues in my testimony:

Palo Verde Steam Generator – This adjustment decreases plant in service by $36.7 million and increases accumulated depreciation by the same amount to reflect the retirement of a steam generator that was replaced post test year.

SFAS Deferred Credit – This adjustment reduces rate base by a net amount of $3.886 million to include an ACC jurisdictional deferred credit in rate base that the Company had omitted.

Pension Liability – This adjustment removes the pension liability from rate base net of deferred income taxes.

Working Capital – This adjustment decreases the working capital requirement by $73.3 million, and is primarily attributable to excluding non-cash depreciation expense from the lead/lag calculation and consideration of the long-term interest expense lags.

PWEC Administrative and General Expense - This adjustment decreases operating expense to remove some prior period A&G accounting entries.

DSM Net Lost Revenues – This adjustment increases revenue by $4.9 based on a disallowance of the Company-requested Net Lost Revenue adjustment.

Pension Liability - This adjustment decreases annual operating expenses by $43.695 million to deny APS' request to pre-fund pensions.

Supplemental Executive Retirement Plan – This adjustment decreases operating expenses by $4.173 million to remove the cost of additional retirement benefits afforded only to high-ranking officials.

Decommissioning Expense – This adjustment decreases operating expenses by $715,000 to reflect the actual test year recorded Decommissioning expense.

Tax Consulting Fees – This adjustment decreases test-year expenses to remove tax consulting fees related to a prior period.

Miscellaneous Expense – This adjustment removes various inappropriate expenses such as sponsorships, party supplies, and bobblehead toy figurines.

Unregulated Operations - This adjustment removes from operating income the revenues and expenses attributable to APS' unregulated Trading and Marketing department.

Lobbying and Political Activities Expense - This adjustment decreases operating expenses by $166,000 to remove expenditures related to lobbying and other political activities.

Amortization Expense - This adjustment decreases amortization expense by $6.991 million to remove an unsupported increase in amortization expense.

PSA Changes – This section examines the Company's requested changes in its PSA mechanism, and recommends denial of the requested change in sharing of hedge gains and losses.

Hook-up Fees –This section examines the merits of using hook-up fees to mitigate the cost of growth.

Environmental Improvement Charge – This section recommends denial of a Company-proposed adjustor that would require ratepayers to pay for environmental improvements prior to their construction and in-service date.

Demand Side Management – This section discusses RUCO's recommendation regarding DSM expenditures after the three year period covered by Decision No. 67744 has lapsed.

Demand Response Program – RUCO recommends that a task force be formed to explore opportunities for load shaving and shifting through Demand Response Programs.

Environmental Portfolio Standard – This section discusses the pending revisions to the EPS.

RATE BASE

Rate Base Adjustment #1 – Palo Verde Steam Generator

Q. Please discuss Rate Base Adjustment #1.

A. The Company has proposed a proforma adjustment to include in rate base the cost of a new steam generator that was added to Palo Verde Unit 1 shortly after the end of the test year. The Company's proforma neglects to reflect the retirement of the old steam generator. An adjustment is necessary to reduce plant by $34.3 million and increase accumulated depreciation by $34.3 million to reflect the retirement of the old generator. This adjustment has a net effect on rate base of zero, however, as discussed in the testimony of William Rigsby, will have an impact on depreciation expense.

Rate Base Adjustment #2 – Deferred Credit

Q. Did you review the deferred debits and deferred credits that the Company has included in its test-year rate base?

A. Yes. APS provided a workpaper that identified each deferred debit and each deferred credit that resided on its balance sheet at the end of the test year. This workpaper also identified which of these items the Company had included in rate base in this case.

Q. After reviewing this workpaper did you understand in each case why the deferred credit or deferred debit was either included or not included in rate base?

A. No, not in all cases. Sometimes it was clearly evident; for example, deferrals related to FERC settlements would be excluded as non-ACC jurisdictional. In other cases where it was not clear why APS either excluded or included certain items, I issued data requests inquiring as to the Company's reason for its particular treatment. Pursuant to that discovery, the Company acknowledged that one of the deferred credits that it had not included in rate base, in fact, should have been included.

Q. Please describe that deferred credit.

A. The deferred credit related to semi-monthly payments that are made to employees that are on long-term disability. Since these are payroll benefit related costs, the credit appropriately should have been included in rate base.

Q. What adjustment have you made?

A. As shown on Schedule MDC-3 Adjustment #2, I have decreased the rate base by $6.376 million to include this deferred credit, and increased rate base by $2.490 million to include the deferred income taxes related to this item. My net adjustment is a decrease in rate base of $3.886 million.

Rate Base Adjustment #4 - Supplemental Executive Retirement Plan (SERP)

Q. What is the Supplemental Executive Retirement Plan?

A. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company.

Q. Does this select group of employees receive the SERP in lieu of the retirement plan available to all APS employees?

A. No. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing electric service. These individuals are already generously compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees, it should do so at its own expense.

Q. Are you aware of any Commission precedent on this issue?

A. Yes. In a recent Southwest Gas rate case the Commission denied recovery of SERP cost and stated the following:

> [W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of

> reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers. [Decision No. 68487, at page 19].

Q. What adjustment are you recommending?

A. As shown on Schedule MDC-4, I have removed the $50.175 million deferred credit and the $19.593 million in accumulated deferred income taxes associated with the SERP from rate base. I have also adjusted test-year operating expenses, which is discussed later in the Operating Income section of my testimony.

Rate Base Adjustment #5 - Working Capital

Q. What level of working capital has the Company requested?

A. APS is requesting $168.1 million in working capital, which is comprised of negative cash working capital of $29.1 million, $106.4 million in Materials and Supplies, $85.3 million in Fuel Inventory, and $5.5 million in Prepayments.

Q. How did the Company calculate its $168.1 million working capital request?

A. The Company utilized its test year-end inventory and prepayment balances to quantify those aspects of its working capital request. The Company utilized a lead/lag study to quantify its cash working capital calculation.

Q. Do you agree with the methodologies the Company used to quantify its cash working capital request?

A. Yes. A lead/lag study is the most accurate way of measuring a utility's cash working capital needs, and as such I agree with the use of this methodology. I do, however, differ on many of the inputs used in the Company's cash working capital requirement.

Q. Please discuss the specific disagreements you have with the Company's lead/lag inputs.

A. First, the Company has included depreciation expense in its cash working capital calculation. This is incorrect. A company's cash working capital requirement is the amount of cash the company must have on hand to cover expenses that must be paid before revenues are available (received) to make those expense payments. Depreciation is not a cash expense item and should not be included in the calculation of cash working capital.

Q. Has it been the Commission's policy to exclude depreciation for the cash working capital calculation?

A. Yes. The Commission has consistently rejected the inclusion of depreciation expense in cash working capital requirements.

Q. What other aspects of APS' cash working capital calculation do you disagree with?

A. The Company has failed to reflect the expense lags associated with its long-term debt in its calculation. Long-term debt interest has a large expense lag since it generally is paid only once or twice a year. Thus, omission of the interest lag will tend to overstate cash working capital requirements.

Q. What adjustment have you made to correct these deficiencies?

A. As shown on Schedule MDC-5, page 2, I have removed depreciation expense from the lead/lag calculation and added an interest expense lead/lag calculation.

Q. Have you made any other adjustments to the Company's lead/lag calculation?

A. The only other adjustment I have made is to substitute RUCO's recommended expense levels for the Company's. The entire adjustment, however, is primarily attributable to the depreciation and interest expense factors and decreases cash working capital by $78.2 million.

OPERATING INCOME

Operating Adjustment #1 – PWEC Administrative and General (A&G) Expense

Q. Please discuss the Company's proposed adjustment for PWEC A&G expense.

A. APS' test-year operating expenses include only two months of PWEC administrative and general expenses. The remaining ten months of PWEC A&G are reflected on PWEC's books and records. As a result, the Company proposes a proforma adjustment to transfer the actual A&G expenses incurred at PWEC to APS and thereby reflect twelve months of PWEC A&G in the test year.

Q. Do you agree with this adjustment?

A. Yes, in principle I agree. The PWEC assets were not owned by APS for the entire test year; thus, it is appropriate to annualize this expense at the APS level to ensure full recovery of these expenses in new rates. I also agree that use of the actual PWEC expenses to quantify the adjustment is more appropriate than estimates or imputed amounts. However, through discovery in this case I became aware that the recorded PWEC A&G expenses contained some out-of-period expenses. Specifically, the test-year recorded PWEC expenses include $2 million in out-of-test-year shared services depreciation expense and $3.098 million in out-of-period rent expense.

Q. What adjustment do you recommend?

A. An adjustment is necessary to remove these out-of-test-year expenses so that new rates will not be burdened with redundant costs. As shown on Schedule MDC-7, Operating Adjustment #1, I have decreased test-year operating expenses by $5.098 million.

Operating Adjustment #3 - DSM – Net Lost Revenues

Q. Please discuss the adjustment that APS is proposing regarding Net Lost Revenues.

A. APS is proposing an adjustment that would decrease test-year revenues by $4.9 million, to reflect the Company's estimate of future sales that will be lost as a result of effective Demand Side Management (DSM) programs.

Q. How did the Company calculate its proposed Net Lost Revenue Adjustment?

A. First, the Company estimated that the DSM plans it submitted for approval to the Commission in July 2005 would result in a loss in sales of 94,201 MWh annually over the next three years. Second, APS calculated the resultant decrease in revenue and expenses that would result from the 94,201 MWh loss in sales. The net of these two amounts is APS' $4.9 million proposed Net Lost Revenue adjustment.

Q. Is this adjustment appropriate?

A. No. This adjustment is inappropriate for three reasons. First, the adjustment seeks to recover estimated lost revenues and expenses that have not actually been realized. For this reason the proposed adjustment violates the known and measurable principle of ratemaking. Second, the adjustment seeks to recover post-test-year losses in revenue, yet fails to recognize post-test-year gains in revenue from customer growth. This violates the matching principle of ratemaking. Third, the settlement agreement approved in Decision No. 67744 specifically precludes the recovery of Net Lost Revenues. The proposed adjustment is therefore in violation of the terms of the settlement agreement.

Q. Please provide further discussion regarding the known and measurable issue.

A. This Commission has traditionally adhered to the known and measurable principle when it sets rates. This principle requires that, in order to be eligible for rate recovery, requested amounts must be verifiable and quantifiable. APS' estimates of future consumption losses resulting from DSM programs that have not been in effect for even a full year, do not meet this standard.

Q. Please further discuss the matching principle issue.

A. Ratemaking standards require a matching between revenues, expenses, and investment used in the rate setting process. Biased rates result when a Company is allowed to pick and choose which revenue and expenses it desires to reflect on a post-test-year basis, and which revenues and expenses it desires to recover on a test-year basis. Thus, biased rates will result if APS is permitted to recognize post-test-year lost revenue and not recognize post-year revenue gained as a result of growth.

Q. Please discuss the violation of the settlement agreement issue.

A. The settlement agreement adopted in Decision No. 67744 specifically precludes the recovery Net Lost Revenue. Paragraph 46 of the settlement agreement states the following regarding Net Lost Revenues:

> This agreement does not provide for the recovery of net lost revenues. Except to the extent reflected in a test year to establish APS rates in future rate proceedings, or unless otherwise authorized by the Commission in a separate non-rate case proceeding, APS shall not recover or seek to recover net lost revenues on a going forward basis. In no event will APS recover or seek to recover net lost revenues incurred in periods prior to such a test year or for periods prior to the Commission's authorization of net lost revenue recovery in a separate non-rate case proceeding. In addition, no recovery of net lost revenues will reduce the DSM spending commitment embodied in this agreement or be considered as an eligible DSM-related item for purposes of this section.

APS' proposed net lost revenue adjustment in this case would reduce the three-year $48 million DSM spending commitment contained in the settlement agreement and, as a result, is a direct violation of Decision No. 67744.

Q. What adjustment have you made?

A. As shown on Schedule MDC-7 I have increased test-year revenues by $4.9 million to remove the net lost revenue adjustment.

Operating Adjustment #4 - Pension Liability

Q. Is the Company requesting a large increase in its pension expense?

A. Yes. The Company is requesting a $43.7 million increase in its cost of service to accelerate the funding of what the Company describes as an "underfunded pension liability".

Q. What does the Company mean by the term "underfunded pension liability"?

A. The underfunded pension liability is the difference between the projected benefit obligation the Company has for employee pensions and the fair value of the plan's assets. APS is claiming an underfunded pension liability of $389 million.

Q. What creates an underfunded pension liability?

A. This liability can be created in a number of ways. The projected benefit obligation will tend to increase when interest rates are low, because it is based on actuarial projections of future payments to retirees, discounted to the present. However, poor earnings on the fund, contributing the bare minimum to the fund, inflated actuarial projections, etc. can also result in an underfunded pension liability.

Q. Does this underfunded pension liability mean that APS has a deficit and that its retirees are in danger of losing their pensions?

A. No. It merely means that the amount of APS' estimated future obligation to its retirees exceeds the amount that APS currently has funded.

Q. Can this situation change without the need to increase current funding?

A. Yes. First, the entire calculation is based on myriad assumptions including interest rates, mortality rates, retirement ages, and discount rates. Interest rates hit an all-time low during the period of time that APS' pension became underfunded. The recent increases in interest rates will have a mitigating effect.

Q. If there is no real deficit and APS employee pensions are not at risk, why should ratepayers fund this liability now?

A. RUCO believes ratepayers should not be required to fund this liability today. The Company's proposal in this case is to have ratepayers pre-fund this liability over the next five years, and for APS to then credit back the funding to ratepayers over the subsequent ten-year period. The proposal is really akin to ratepayers providing an interest-free loan to the Company (payable over five years) and APS then paying ratepayers back for their loan over ten years.

Q. Is this proposal reasonable?

A. No. During this period of rising gas and energy costs it is not fair to further burden ratepayers with pre-funding $43.7 million in pension costs over the next five years. The Company's proposal also would create intergenerational equities since the ratepayers who fund the unfunded pension over the next five years may not be the same ratepayers that receive the reimbursement over the subsequent ten years.

Q. What adjustment have you made?

A. As shown on Schedule MDC-7, I have decreased test-year operating expenses by $43.7 million to remove the cost of pre-funding the pension liability.

Operating Adjustment #5 - Supplemental Executive Retirement Program

Q. Please discuss Operating Adjustment #5 - SERP.

A. This adjustment decreases operating expenses to remove the $4.17 million test-year SERP expense. As discussed in the rate base section of my testimony, the Commission has previously determined that is not reasonable to require ratepayers to pay the cost of providing additional executive "perks" such as the SERP.

Operating Adjustment #7 – Decommissioning Expense

Q. Please discuss the Company's proposed adjustment for decommissioning expense.

A. In Decision No. 67744 the Commission approved a decommissioning accrual schedule for APS. That schedule required accruals of $19.211 million for the period 2005 through 2015. APS recorded decommissioning expense of $15.328 million during the test year and is thus requesting a proforma adjustment of $3.883 million to reflect the level of expense authorized in Decision. No. 67744.

Q. Do you agree with this adjustment?

A. I agree that the level of decommissioning expense authorized in Decision No. 67744 should be reflected in the test year. I disagree, however, with the amount of the adjustment.

Q. Please explain.

A. The APS adjustment is based on a test-year recorded amount of $15.328 million. Through discovery in this case I learned the actual test-year recorded amount of Decommissioning expense was $16.093 million. As shown on Schedule MDC-8, it is necessary to reduce the APS proposed decommissioning adjustment by $765,000.

Operating Adjustment #9 – Out-of Period Expense -Tax Consulting Fees

Q. Please explain your adjustment to remove an out-of-period tax consulting fee.

A. During 2003 the joint owners of the Palo Verde Nuclear Plants disputed the manner in which APS has accounted for certain outside tax consulting fees. The dispute was resolved in July 2005, and resulted in a $1.225 million increase in test-year expenses that were attributable to events in 2003. I have therefore decreased test-year expenses by $1.225 million to remove this out-of-period expense.

Operating Adjustment #11 – Miscellaneous Expenses

Q. As part of your review and analysis in this case, did you perform an audit of various APS miscellaneous expense accounts?

A. Yes. Despite APS' adjustment removing certain sport sponsorship and advertising expenses, I was concerned that the Company's test-year miscellaneous accounts contained other items that were unnecessary in the provisioning of electric service. Pursuant to this concern I selected a sample of test-year APS expense invoices to review.

Q. Which accounts were included in your sample?

A. The following accounts were included in my sample:

Account 909 – Information & Institutional Advertising Expense

Account 912 – Demonstrating & Selling Expense

Account 913 – Advertising Expense

Account 930.2 – Miscellaneous General Expense

From each account, I selected three months during the test year from which I selected my sample.

Q. What did your review of your sample reveal?

A. I found a number of expenditures in my sample that should not be included in rates.

Q. Hasn't APS already removed some of these inappropriate items in their rate filing?

A. Yes. APS has made a $6.140 million adjustment to remove various sport sponsorships and advertising expenses. The Company's adjustment is limited to expenses in account 913. Mr. Rigsby discusses the APS advertising adjustment in his testimony.

Q. What additional expenses did you identify beyond advertising expenses that should not be included in rates?

A. I identified a number of sponsorships and donations to community organizations including the Dodge Theatre, Greater Phoenix Chamber of Commerce, and Peoria Gains Event. I also identified expenditures for martini glasses, strobe lights, balloons, other party supplies, and catered employee lunches. Traditionally, these are not the types of expenditures the Commission has allowed utilities to recover through rates. Schedule MDC-9 identifies each expenditure that I'm recommending not be included in rates and results in a $525,555 reduction in test-year expenses.

Q. Does your adjustment preclude the Company from supporting the communities in which it operates and preclude the Company from sponsoring employee celebrations and or meals?

A. No. My adjustment merely recognizes that while supporting the community may be a good thing, it primarily benefits shareholders as it builds goodwill and enhances the Company's image. Certainly APS can continue this support at shareholder expense.

Q. Does this adjustment result in a disallowance of all test-year inappropriate items?

A. Probably not. The adjustment only represents those inappropriate items that were present in my sample. Given RUCO's staffing constraints, it would be impossible to review each and every test-year invoice in those four accounts. As it was, the sample review took three RUCO employees better than half a day to complete. Presumably had we reviewed each and every expenditure the adjustment would have been larger. Thus, I suspect my proposed disallowance is very conservative.

Operating Adjustment #12 – Unregulated Expenses

Q. Please discuss your proposed adjustment related to unregulated revenues and expenses.

A. The Company acknowledged during the discovery process that it had failed to adjust its test-year income statement to exclude revenues and expenses related to unregulated Marketing and Trading operations. Thus, embedded in the Company's rate request is the test-year operating losses of APS' unregulated Marketing and Trading operation. These losses are not appropriately recovered through regulated rates; therefore, made an adjustment to remove the unregulated losses of $15.149 million from APS' test-ear expenses.

Operating Adjustment #13 – Lobbying Expense

Q. Did APS incur any lobbying expenses in the test year?

A. Yes. APS incurred lobbying expenses during the test year through its Federal Affairs and Public Affairs departments.

Q. Did the Company record its lobbying expenses in below the line accounts as required by the Uniform System of Accounts?

A. Some test-ear lobbying expenses were recorded below the line, others were not. The Federal Affairs department recorded its $137,686 in lobbying activity costs above the line, whereas the Public Affairs department recorded $341,502 in lobbying expense below the line.

Q. Does this mean that the Company is seeking rate recovery of some lobbying and political activity costs?

A. Yes. To the extent these types of costs reside in above-the-line accounts and have not been removed via a proforma adjustment, the Company is seeking recovery.

Q. Have you identified above-the-line lobbying costs that should be adjusted out of the test year?

A. Yes. First, the Federal Affairs department incurred $137,686 for paid outside lobbyists and $696,629 in other expenses. The entire expense for outside lobbyists should be disallowed, and 50% of the other expenses of the Federal Affairs department should also be removed.

Q. Why are you recommending disallowance of 50% of the other expenses of this department?

A. In response to data requests, the Company provided descriptions of the duties and functions of the Federal Affairs Department. Having reviewed this information, I believe approximately half of this department's time is spent on activities that involve lobbying and political activities that are more appropriately assigned to shareholders than ratepayers.

Q. Why do you believe that?

A. APS provided the following job descriptions for the employees that work in this department:

> Represents the company to the federal government on proposed legislation that is of vital concerns to the company and customers. Develops and maintains credible and professional relationships with legislators, various heads of federal agencies and their assistants and staff in order to affect favorable public policy decisions as they impact Pinnacle West.

Q. What other lobbying costs should be disallowed?

A. Second, 50% of the $599,309 payroll costs incurred in the Public Affairs department should be disallowed. APS described the function of the Public Affairs employees as follows:

> To plan, coordinate and direct a program to insure a favorable Public Affairs/Governmental climate with the legislature and state, county and local government agencies in order to effect favorable public policy decisions as they relate to APS.

> Ensure favorable company image with governmental, civic and public opinion leaders by representation and by maintaining working liaison with industry representatives and associations.

Q. What is your total recommended adjustment for lobbying and image-enhancing expenses?

A. As shown on Schedule MDC-10, I have removed 100% of the lobbying expenses of the Federal Affairs Department and 50% of that department's other expenses. I have removed 50% of the Public Affairs department payroll costs. There is no reduction necessary for Public Affairs lobbying expense because that was all recorded in a below-the-line account. My adjustment reduces test-year expenses by a total of $785,654.

Operating Adjustment #14 – Amortization Expense

Q. Has the Company requested an increase in its amortization expense for intangible and general plant?

A. Yes. The Company has requested an increase in amortization of intangibles and general plant of over $10 million.

Q. What is the basis for this large requested increase?

A. Despite having issued discovery on this issue, it remains unclear from the Company's response why it believes such a large increase in amortization is justified. While APS did perform a depreciation study in support of its increased depreciation expense, it specifically notes that the amortization of intangibles and general plant were not studied. Thus, there is no objective basis for the large increase.

Q. Is a $10 million increase in amortization expense warranted?

A. No. When I examined the intangible and general plant account balances at December 31, 2004 and at September 30, 2005 the assets in these accounts had increased by approximately 5.5%; yet, APS is requesting a 35% increase in annual amortization expense for these accounts. There is no study that supports such an increase or explanation why such a disproportionate increase is necessary.

Q. Are you proposing an adjustment?

A. Yes. At a time when APS is proposing a 21% increase in electric rates, it is unreasonable to arbitrarily increase amortization expense by over $10 million. As shown on Schedule MDC-11, I have recalculated a more reasonable increase in amortization by multiplying the $29 million increase in intangible and general plant balances by the composite amortization rate of 10.38%. This renders a more justifiable increase in amortization expense of $3.1 million based on the increased value of the assets. This adjustment results in a $6.991 million decrease in Company proposed amortization expense.

POWER SUPPLY ADJUSTOR

Q. Is the Company requesting any changes in its currently authorized Power Supply Adjustor (PSA)?

A. Yes. APS is proposing the following four changes to its PSA:

1) Elimination of the total fuel cost cap;
2) Change the cumulative four mil cap on the PSA annual adjustor to an annual cap;
3) Exclude renewable resources and fixed costs of PPAs acquired through the competitive bidding process from the 90/10 sharing;
4) Exclude 10% of the gains and losses realized on hedging from both the base fuel amount and in subsequent PSA operations.

Q. Why is APS proposing these changes to the existing PSA?

A. First and foremost, the Company was ordered to look at changes to the PSA in this rate case by Decision No. 68685 where the Commission stated:

> IT IS FURTHER ORDERED that the issue of the timeliness of recovery of fuel and purchased power costs and any permanent modifications to Arizona Public Service Company's Power Supply Adjustor shall be further addressed in the pending general rate proceeding. [Decision No. 68685 at page 39]

Q. Please discuss RUCO's position on these proposed changes to the PSA.

A. RUCO supports the first three of the proposed changes. In light of the recent downgrades in APS credit ratings, the need to maintain a financially healthy public service company, and the goal of sending customers the appropriate price signals, I believe lifting the overall cap on prudently incurred fuel costs, as well as making the four mil cap an annual cap, is in the public interest. The consequences[2] over the last year from having these caps are not something that we would want to see repeated. Further, since any changes in the PSA adjustor and surcharge are always subject to Commission approval, the caps serve no real purpose. The Commission has the ability and authority to deny recovery of any imprudently incurred costs; and because of this, the ratepayers are protected.

RUCO also believes excluding renewable energy from the 90/10 sharing is also appropriate. It is an accepted fact that some forms of renewable energy will exceed the cost of traditional generation and equally accepted that despite of the additional cost, greater utilization of renewable energy is still a desirable public policy goal. Given this, it seems highly unfair to require APS to absorb 10% of the excess cost. The 90/10 sharing was intended to incent the Company to find ways to contain its fuel costs, and accordingly it does not make much sense to impose that sharing on

[2] The consequences include a down-grade in APS' bond rating and the filing of an emergency rate increase request.

already higher cost renewables. RUCO further does not oppose excluding the fixed costs of PPAs acquired through competitive bidding from the 90/10 sharing. At first blush, it appeared that exempting PPAs from the 90/10 sharing would create a perverse incentive for the Company to favor self-build over a competitive PPA even if the cost of the PPA were lower[3] than self-build. However, the limited moratorium imposed by Decision No. 67744 on self-build would preclude APS from exercising such a perverse incentive. Thus, because of the protection of the self-build moratorium I believe there is no harm in granting the Company's request to exempt PPA fixed costs from the 90/10 sharing. This, however is an issue that will need to be revisited when the limited self-build moratorium is lifted in 2015, because such a perverse incentive could be exercised at that time.

Q. What is RUCO's position on the fourth proposed change in the PSA?

A. RUCO does not support the Company's proposal to make hedging gains and losses subject to the 90/10 sharing mechanism, and recommends that the Commission deny this request.

[3] The perverse incentive arises from the fact that under the current 90/10 sharing the fixed costs of power acquired under a competitive PPA are subject to sharing whereas the fixed costs of self-build are not subject to sharing. Thus, even if a PPA cost less than self-build APS would have the incentive to choose self-build simply because the fixed costs of self-build would not be subject to the 10% sharing yet the fixed costs of PPA would be subject to sharing.

Q. Please explain.

A. The purpose of the 90/10 sharing mechanism is to provide an incentive for the Company to control its fuel and purchase power costs. The purpose of APS' hedging program is not to achieve lower fuel costs, but rather to reduce volatility by smoothing out wide fluctuations in fuel costs. Granting APS a 10% reward or 10% penalty for its hedging results could distort what is currently a program to smooth out cost fluctuations into a speculative market strategy. It is not in the public interest to provide an incentive for APS to speculate with ratepayer money.

Q. Will the above recommended changes in the PSA have a positive result?

A. Yes, I believe so. The PSA needs to be flexible enough to allow the Company to recover its prudently incurred fuel and purchased power costs so it can remain financially healthy, while at the same time hold ratepayers harmless from imprudent or self-serving actions by the Company. I believe the PSA with the above-discussed modifications will accomplish these goals.

CUSTOMER GROWTH – HOOK-UP FEES

Q. What is RUCO's position on the use of new customer hook-up fees to help defray the cost of growth?

A. Hook-up fees, if properly designed and not relied on exclusively to fund growth, can be an effective tool in controlling rate increases. It is a tool that has long been recognized and utilized in the water and sewer industries, but rarely in the electric industry. Hook-up fees can be an effective way of having growth pay for itself.

Q. Does RUCO support the implementation of a hook-up fee tariff in this case?

A. Utilization of a hook-up fee to defray the cost of growth in the electric industry is certainly beguiling, however, it is not an action that should be taken without being fully vetted and carefully researched. Implementation of a hook-up fee would not be without ramifications in the community. Effects on the housing industry, economic development, and future growth rates, to mention a few, would all be impacted by a policy of charging hook-up fees to new customers.

Q. If a hook-up fee were to be implemented how much should it be?

A. That is another issue that would need to be fully analyzed prior to implementing a hook-up. If the amount were set too high, it could stifle growth and economic development. If set too low, it would not have the desired impact of having growth pay for itself, while at the same time create administrative and customer relation issues. Certainly, some guidance could be obtained by looking at the embedded cost of the existing plant.

Q. What currently is the embedded cost of plant per kwh?

A. I calculated the original cost of the current plant per annual kwh of generation as $0.21. If the per kwh cost of the existing plant were multiplied by the average annual consumption in each customer class it would result in the following hook-fees:

Residential	$2,900
Commercial	$23,445
Industrial	$147,509

While this may not be the right manner in which to determine what a hook-up fee should be, it does demonstrate the potential magnitude of the impact such a tariff would have. Implementation of hook-up fee of these magnitudes is not an action that should be undertaken without careful study.

Q. What does RUCO recommend regarding hook-up fees?

A. RUCO believes that some format of the idea has merit, and if properly analyzed, could be an effective way in which to mitigate the cost of growth. However, because of the novelty of the hook-up fee tariff in this industry, as well as its dependence on the level of growth that actually occurs, and the potential impacts on stakeholders other than the Company and its customers, RUCO recommends that a Workshop process be put in place to allow all stakeholders to participate and formulate an effective policy regarding hook-up fees in the electric industry.

ENVIRNOMENTAL IMPROVEMENT CHARGE

Q. Is APS requesting a special adjustor mechanism for the costs it plans to spend on plant additions whose purpose is to improve the environmental friendliness of its power plants?

A. Yes. The Company is requesting what it calls an Environmental Improvement Charge (EIC) which would allow it to estimate at the beginning of each year its annual costs associated with environmental improvement and implement a surcharge to begin recovering those costs. Eligible costs would include estimated plant investment in environmental improvements, as well as estimated costs of maintaining the environmental improvements. The proposed mechanism would be trued-up to actual costs each following year, thus, it is more akin to an adjustor mechanism than a surcharge.

Q. Isn't this proposal at odds with the normal ratemaking process for plant additions and improvements?

A. Yes. The normal ratemaking process requires plant to be actually built (known and measurable) and in-service (used and useful) prior to being given ratemaking consideration in the context of a rate case. APS' proposed EIC not only would violate those ratemaking principles, it would circumvent the constitutional requirement of a fair value finding when revising rates by allowing changes in rates outside of a rate case.

Q. How does APS justify the implementation of an EIC that would violate all accepted ratemaking standards?

A. The Company argues the EIC is justified for the following reasons:

1) Protecting the environment is in the public interest;

2) The Commission can foster environmental improvement by approving mechanisms that permit utilities to make and recover environmental investments;

3) Environmental improvements are not revenue-producing, and may be a challenge for APS to fund absent the proposed mechanism.

Q. Do you agree with this rationale?

A. No. I have never seen a situation where ratepayers were required to prepay for utility plant investment, even if it is in the public interest and a challenge to fund[4]. Ratepayers are required to reimburse utilities for their prudent and reasonable operating expenses and a fair rate of return on the Company's investment. In the name of "fostering" environmental improvement, APS would have the Commission authorize increased rates so that ratepayers could prepay for plant. This very notion is absurd and

[4] Even in the case of the EPA arsenic mandate, the Commission has continued to require that the plant actually be in-service prior to allowing the arsenic surcharge to be collected

would cast the ratepayers in the role of investors, albeit without any return on investment.

Q. Does the Commission need to "foster" environmental improvements?

A. No. APS acknowledges in its direct testimony that a number of laws and regulations that have recently been enacted require the Company to make environmental improvements in order to comply. These include revisions to the New Resource rule under the Clean Air Act, a new EPA Clean Air Mercury rule, a Clean Air Visibility rule, as well as the pending Clear Skies Act. The Company has all the incentive it needs to make these improvements – because they are mandated.

Q. What is RUCO's recommendation?

A. The Commission should deny the Company's request for an EIC that would require ratepayers to pay for plant investment prior to that investment actually being made.

DEMAND SIDE MANAGEMENT

Q. Please describe the current status of APS' DSM programs.

A. Pursuant to Decision No. 67744, which the Commission adopted in April 2005, the Company is required to spend at least $48 million on DSM over a three-year period. APS' base rates are currently set to annually recover $10 million of that amount. The remaining $18 million is to be recovered through a DSM adjustor mechanism. Pursuant to paragraph 54 of the settlement agreement approved in Decision No. 67744, APS formed a collaborative DSM working group, which designed DSM programs that were ultimately submitted by the ACC Staff to the Commissioners for their approval. A number of programs have received Commission approval and are currently in effect. However, as a result of some delays in the approval process, APS did not spend during the test year the required $10 million allotted to base rates.

Q. *Is an adjustment to rates necessary in light of the inability of APS to spend the entire $10 million in base rates during the test year?*

A. No. Paragraph 51 of the settlement agreement would require refunds if the entire $30 million in base rates were not expended over the three-year period of the agreement. Thus, the Company can "make-up" in years two and three for the first year's under spending, as well as expend the additional $18 million required under the adjustor mechanism.

Q. In the instant case, is APS proposing any modifications to the DSM provisions as set out in the settlement agreement?

A. Yes. APS is proposing that any funds expended over the $10 million rate base amount (and thereby included in the deferral account for recovery through the DSM adjustor) be allowed to accrue interest.

Q. Do you agree with this proposal?

A. No. This is not something that was considered as part of the settlement agreement and RUCO believes it would be inappropriate to modify the agreement prior to the expiration of the terms of that agreement. Further, during the test year APS collected $10 million in DSM funds and only expended $5.093 million. The remaining $4.907 million has a time value of money to APS. Thus, APS has already benefited from the time value of the unexpended test-year funds. For these reasons, I do not believe APS' interest-earning request is warranted and I recommend the request be denied.

Q. What is APS proposing regarding DSM once the three-year period included in the settlement agreement expires in 2008?

A. APS does not directly address this issue, so their position is unclear. It would appear that the Company plans to continue spending $10 million a year on DSM after the expiration of the settlement agreement, since APS has embedded this amount in its requested rates. However, even this is not explicitly addressed in the Company's testimony.

Q. Is it important that the future of DSM funding be addressed in this docket?

A. Yes. It is important that the future treatment, post-expiration of the settlement agreement, be resolved in this docket to ensure the continuity of existing and future programs. APS has made no proposal regarding what happens after the conclusion of the three-year period addressed in the settlement agreement; thus, it is imperative that this issue be resolved in this docket.

Q. What are RUCO's recommendations regarding DSM post-expiration of the settlement agreement terms?

A. RUCO recommends that the $10 million of required spending in base rates continue as long as the rates set in this docket remain in effect[5]. The DSM surcharge should remain in effect also. However, the $6 million annual mandatory spending in the surcharge account should be increased to $10 million, for a total annual DSM spending requirement of $20 million.

Q. Why are you recommending an increase in DSM funding?

A. At the time of the settlement agreement, there was never any question about the value and desirability of an aggressive DSM program; however, there were some concerns regarding the time it might take to "ramp" up spending and in implementing new programs. This is no longer a concern since APS now has "up and running" programs. The additional $4 million will allow for more new programs and more savings through DSM. The more the cost of energy and generation increase, the more valuable a resource DSM becomes.

[5] The $10 million would continue to be subject to the applicable provisions of the settlement agreement.

DEMAND RESPONSE PROGRAMS

Q. Please discuss Demand Response.

A. In the context of APS' last rate case, there was much discussion regarding the value of Demand Response Programs. Decision No. 67744 required the Company to propose flexible Time of Use Rates, which the Company has proposed, and are now in place. While the Commission recognized the desirability of additional Demand Response Programs, the issue was put off for another day.

Q. Should this issue now be examined?

A. Yes. Demand Response Programs can be a valuable resource for an electric utility to manage its peak loads. In fact, after the Westwing substation fire in the summer of 2004, the Company was very successful in cutting load through informal demand response efforts. RUCO believes that in this time of rising energy costs, examining ways to formalize Demand Response programs would be beneficial. RUCO recognizes that some Demand Response programs are not particularly a perfect fit with residential loads given infrastructure constraints; however, many commercial and industrial loads are potentially well suited for interruptible rates. Further, programs can be developed that can incent customers to shift load during peak periods, as well as in emergency situations.

Q. What do you recommend?

A. RUCO recommends that a task force be formed to explore opportunities for load shaving and load shifting through Demand Response programs. The task force would initially be comprised of APS, ACC Staff, RUCO, and any other interested stakeholders.

ENVIRONMENTAL PORTFOLIO STANDARD

Q. Is the Company proposing any changes to it Environmental Portfolio Standard tariff?

A. No. The Company reiterates its commitment to EPS and discusses its EPS efforts to-date.

Q. Why isn't the Company proposing any changes?

A. The Company recognizes that there is another process in place[6] that is designed to deal with the renewable resource issue on a global basis for all Arizona affected electric companies. The Company also recognizes that the settlement agreement in Decision No. 67744 authorized the then-EPS surcharge to be converted to an adjustor mechanism that would allow any Commission-ordered changes in the EPS to be recovered through the adjustor, without a need for a rate case.

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[6] The proposed rules under the Renewable Energy Standard and Tariff, Docket No. RE-00000c-05-0030.

Q. Has the Commission approved any changes to the EPS to-date?

A. No, not yet. However, it is anticipated that could well occur before this rate case is heard in October 2006.

Q. Is there any reason to address revisions to APS' EPS in the context of this rate case?

A. No. In Decision No. 67744 the Commission has already established a mechanism for APS that will allow the Company to recover any incremental costs associated with any potential revisions to the Renewable rules. Further, it is anticipated that any proposed changes in those rules will be addressed by the Commission for the electric industry as a whole, prior to a hearing in the instant matter.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX I

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION: University of Michigan, Dearborn
B.S.A., Accounting 1989

CERTIFICATION: Certified Public Accountant - Michigan
Certified Public Accountant - Arizona

EXPERIENCE: Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85007
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office
Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office

Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office
Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office

Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office

Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office

Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Corporation	T-01051B-03-0454 & T-00000D-00-0672	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-04-0408	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0280	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-04-0876	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0405	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0718	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-06-0009	Residential Utility Consumer Office
Black Mountain Sewer Corporation	SW-02361A-05-0657	Residential Utility Consumer Office

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816
TABLE OF CONTENTS TO SCHEDULES MDC

SCHEDULE #

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	ADJUSTED RATE BASE	$ 4,466,697	$ 7,774,812	$ 6,120,755	$ 4,463,358	$ 7,728,180	$ 6,095,769
2	OPERATING INCOME	12,780			82,456		
3	ADJUSTMENT FOR HEDGE VALUE	103,124			103,124		
4	ADJUSTED OPERATING INCOME	115,904	115,904	115,904	185,580	185,580	185,580
5	CURRENT RATE OF RETURN (L4 / L1)	2.59%	1.49%	1.89%	4.16%	2.40%	3.04%
6	REQUIRED OPERATING INCOME (L7 * L1)	389,943	389,943	389,943	327,164	327,164	327,164
7	REQUIRED RATE OF RETURN	8.73%	5.02%	6.37%	7.33%	4.23%	5.37%
8	OPERATING INCOME DE(SUF)FICIENCY (L5 - L2)	377,163			244,708		
9	ADJUSTMENT FOR HEDGE VALUE	(103,124)			(103,124)		
10	ADJUSTED OPERATING INCOME DEFICIENCY	274,039	274,039	274,039	141,584	141,584	141,584
11	GROSS REVENUE CONVERSION FACTOR	1.6407	1.6407	1.6407	1.6407	1.6407	1.6407
12	GROSS REVENUE INCREASE	618,812			401,492		
13	ADJUSTMENT FOR HEDGE VALUE	(169,196)			(169,196)		
14	REQUESTED INCREASE IN GROSS REVENUES	$ 449,616	$ 449,616	$ 449,616	$ 232,297	$ 232,297	$ 232,297
15	ENVIRONMENTAL IMPROVEMENT CHARGE	4,315	4,315	4,315		-	-
16	TOTAL INCREASE IN RATES	$ 453,931	$ 453,931	$ 453,931	$ 232,297	$ 232,297	$ 232,297
17	CURRENT RETAIL REVENUES T/Y ADJUSTED	$ 2,127,322	$ 2,127,322	$ 2,127,322	$ 2,132,229	$ 2,132,229	$ 2,132,229
18	PROPOSED ANNUAL REVENUE (L16 + L17)	$ 2,581,253	$ 2,581,253	$ 2,581,253	$ 2,364,526	$ 2,364,526	$ 2,364,526
19	PERCENTAGE AVERAGE INCREASE	21.34%	21.34%	21.34%	10.89%	10.89%	10.89%
20	INCREMENTAL INCREASE (NET OF EMERGENCY RATES)	14.87%			4.44%		

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-7, AND MDC-12

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
ACC JURISDICTIONAL RCND RATE BASE (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-1

LINE NO.	DESCRIPTION	(A) TOTAL COMPANY AS FILED	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO ADJUSTED TOTAL COMPANY	(D) RUCO ADJUSTED ACC JURISDICTIONAL
1	GROSS UTILITY PLANT IN SERVICE	$ 17,842,146	$ (60,082)	$ 17,782,064	$ 15,167,943
2	LESS: ACCUMULATED DEPRECIATION & AMORT.	(7,241,636)	63,728	(7,177,908)	(6,107,125)
3	NET UTILITY PLANT IN SERVICE	**$ 10,600,510**	**$ 3,646**	**$ 10,604,156**	**$ 9,060,818**
	DEDUCTIONS:				
4	DEFERRED TAXES	$ (1,205,444)	$ (17,103)	$ (1,222,547)	$ (1,079,534)
5	INVESTMENT TAX CREDITS	-	-	-	-
6	CUSTOMER ADVANCES FOR CONSTRUCTION	(59,807)	-	(59,807)	(59,807)
7	CUSTOMER DEPOSITS	(54,860)	-	(54,860)	(54,860)
8	PENSION LIABILITY	(72,920)	50,175	(22,745)	(21,428)
9	LIABILITY FOR ASSET RETIREMENT	(263,457)	-	(263,457)	(260,419)
10	OTHER DEFERRED CREDITS	(111,791)	(6,376)	(118,167)	(115,729)
11	UNAMORTIZED GAIN-SALE OF UTILITY PLANT	(46,901)	-	(46,901)	(46,360)
12	REGULATORY LIABILITIES	(168,048)	-	(168,048)	(160,744)
13	TOTAL DEDUCTIONS	**$ (1,983,228)**	**$ 26,696**	**$ (1,956,532)**	**$ (1,798,882)**
	ADDITIONS:				
14	REGULATORY ASSETS	$ 84,531	(6,115)	$ 78,416	$ 59,389
15	# MISCELANEOUS DEFERRED DEBITS	42,522		42,522	39,464
16	DEPRECIATION FUND - DECOMMISSIONING	290,537	-	290,537	285,855
17	ALLOWANCE FOR WORKING CAPITAL	168,146	(78,205)	89,941	81,536
18	TOTAL ADDITIONS	**$ 585,736**	**$ (84,320)**	**$ 501,416**	**$ 466,244**
19	TOTAL RATE BASE	**$ 9,203,018**	**$ (53,978)**	**$ 9,149,040**	**$ 7,728,180**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1
COLUMN (B): SCHEDULE MDC-3 x RCND FACTOR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) x JURISDICTIONAL FACTOR

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
GROSS REVENUE CONVERSION FACTOR (000'S)

LINE NO.	DESCRIPTION	TOTAL AMOUNT	REFERENCE
1	REVENUE	1.0000	
2	UNCOLLECTIBLES	0.0000	COMPANY SCH. C-3
3	SUB-TOTAL	1.0000	LINE 1 - LINE 2
4	LESS: TAX RATE	0.3905	NOTE (a)
5	TOTAL	0.6095	LINE 3 - LINE 4
6	REVENUE CONVERSION FACTOR	1.6407	LINE 1/LINE 5

NOTE (a):
CALCULATION OF EFFECTIVE TAX RATE

OPERATING INCOME BEFORE TAXES	100.00%
ARIZONA STATE TAX	6.23%
TAXABLE INCOME FEDERAL	93.77%
FEDERAL INCOME TAX RATE	35.00%
SUBTOTAL	32.82%
ADD STATE TAX RATE	39.05%
LINE 3 ABOVE	100.00%
EFFECTIVE TAX RATE	39.05%

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
ORIGINAL COST RATE BASE (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO TEST YEAR AS ADJUSTED TOTAL COMPANY	(D) RUCO TEST YEAR AS ADJUSTED ACC JURISDICTION
1	GROSS UTILITY PLANT IN SERVICE	$ 10,893,882	$ (36,684)	$ 10,857,198	$ 9,265,004
2	LESS: ACCUMULATED DEPRECIATION & AMORT.	(4,168,540)	36,684	(4,131,856)	(3,515,350)
3	NET UTILITY PLANT IN SERVICE	**$ 6,725,342**	**$ -**	**$ 6,725,342**	**$ 5,749,654**
	DEDUCTIONS:				
4	DEFERRED TAXES	$ (1,205,461)	$ (17,103)	$ (1,222,564)	$ (1,079,551)
5	INVESTMENT TAX CREDITS	-	-	-	-
6	CUSTOMER ADVANCES FOR CONSTRUCTION	(59,807)	-	(59,807)	(59,807)
7	CUSTOMER DEPOSITS	(54,860)	-	(54,860)	(54,860)
8	PENSION LIABILITY	(72,920)	50,175	(22,745)	(21,428)
9	LIABILITY FOR ASSET RETIREMENT	(263,457)	-	(263,457)	(260,419)
10	OTHER DEFERRED CREDITS	(111,791)	(6,376)	(118,167)	(115,729)
11	UNAMORTIZED GAIN-SALE OF UTILITY PLANT	(46,901)	-	(46,901)	
12	REGULATORY LIABILITIES	(168,048)	-	(168,048)	(160,744)
13	TOTAL DEDUCTIONS	**$ (1,983,245)**	**$ 26,696**	**$ (1,956,549)**	**$ (1,752,539)**
	ADDITIONS:				
14	REGULATORY ASSETS	$ 84,531	$ (6,115)	$ 78,416	$ 59,389
15	MISCELANEOUS DEFERRED DEBITS	42,522	-	42,522	39,464
16	DEPRECIATION FUND - DECOMMISSIONING	290,537	-	290,537	285,855
17	ALLOWANCE FOR WORKING CAPITAL	168,146	(78,205)	89,941	81,536
18	TOTAL ADDITIONS	**$ 585,736**	**$ (84,320)**	**$ 501,416**	**$ 466,244**
19	TOTAL RATE BASE	**$ 5,327,833**	**$ (57,624)**	**$ 5,270,209**	**$ 4,463,358**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1
COLUMN (B): SCHEDULE MDC-3
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) x APPROPRIATE JURISDICTIONAL FACTOR

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
SUMMARY OF RATE BASE ADJUSTMENTS (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-3

LINE NO.	DESCRIPTION	(A) TOTAL COMPANY	(B) ADJ. #1	(C) ADJ. #2	(D) ADJ. #3	(E) ADJ. #4	(F) ADJ. #5	(G) RUCO ADJUSTED TOTAL COMPANY
1	GROSS UTILITY PLANT IN SERVICE	$ 10,893,882	$ (36,684)	$ -	$ -	$ -	$ -	$ 10,857,198
2	LESS: ACCUMULATED DEPRECIATION & AMORT.	(4,168,540)	36,684					(4,131,856)
3	NET UTILITY PLANT IN SERVICE	**$ 6,725,342**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6,725,342**
	DEDUCTIONS:							
4	DEFERRED TAXES	$ (1,205,461)	$ -	$ 2,490	$ -	$ (19,593)	$ -	$ (1,222,564)
5	INVESTMENT TAX CREDITS	-						-
6	CUSTOMER ADVANCES FOR CONSTRUCTION	(59,807)						(59,807)
7	CUSTOMER DEPOSITS	(54,860)						(54,860)
8	PENSION LIABILITY	(72,920)				50,175		(22,745)
9	LIABILITY FOR ASSET RETIREMENT	(263,457)						(263,457)
10	OTHER DEFERRED CREDITS	(111,791)		(6,376)				(118,167)
11	UNAMORTIZED GAIN-SALE OF UTILITY PLANT	(46,901)						(46,901)
12	REGULATORY LIABILITIES	(168,048)						(168,048)
13	TOTAL DEDUCTIONS	**$ (1,983,245)**	**$ -**	**$ (3,886)**	**$ -**	**$ 30,582**	**$ -**	**$ (1,956,549)**
	ADDITIONS:							
14	REGULATORY ASSETS	$ 84,531	$ -	$ -	$ (6,115)	$ -	$ -	$ 78,416
15	MISCELANEOUS DEFERRED DEBITS	42,522						42,522
16	DEPRECIATION FUND - DECOMMISSIONING	290,537						290,537
17	ALLOWANCE FOR WORKING CAPITAL	168,146					(78,205)	89,941
18	TOTAL ADDITIONS	**$ 585,736**	**$ -**	**$ -**	**$ (6,115)**	**$ -**	**$ (78,205)**	**$ 501,416**
19	TOTAL RATE BASE	**$ 5,327,833**	**$ -**	**$ (3,886)**	**$ (6,115)**	**$ 30,582**	**$ (78,205)**	**$ 5,270,209**

ADJUSTMENT #:		REFERENCE:
1	RETIRE STEAM GENERTAOR UNIT	TESTIMONY - DIAZ CORTEZ
2	INCLUDE SFAS 112 DEFERRED CREDIT	TESTIMONY - DIAZ CORTEZ
3	REMOVE BARK BEETLE REGULATORY ASSET ADJUSTMENT	TESTIMONY - RIGSBY
4	SERP	SCHEDULE MDC-4
5	WORKING CAPITAL	SCHEDULE MDC-5

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
RATE BASE ADJUSTMENT #4 - SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-4

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	SERP - DEFERRED CREDIT	$50,175,000	COMPANY WP LLR_WP2, B-1(4)
2	SERP - ADIT	($19,593,087)	LINE 1 x EFFECTIVE TAX RATE (39.05%)

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL (000'S)

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	CASH WORKING CAPITAL PER COMPANY	$ (29,139)	COMPANY SCH. B-5, PG. 1
2	CASH WORKING CAPITAL PER RUCO	(107,344)	SCH. MDC-5, PG. 2
3	CASH WORKING CAPITAL ADJUSTMENT	$ (78,205)	LINE 2 - LINE 1
4	MATERIALS & SUPPLIES PER COMPANY	$ 106,427	COMPANY SCH. B-5, PG. 1
5	MATERIALS & SUPPLIES PER RUCO	106,427	COMPANY SCH. E-1, PG. 1
6	MATERIALS & SUPPLIES ADJUSTMENT	$ -	LINE 5 - LINE 4
7	FUEL - COAL AND OIL PER COMPANY	$ 25,452	COMPANY SCH. B-5, PG. 1
8	FUEL - COAL AND OIL PER RUCO	25,452	COMPANY SCH. E-1, PG. 1
9	FUEL - COAL AND OIL ADJUSTMENT	$ -	LINE 7 - LINE 8
10	FUEL - NUCLEAR, NET PER COMPANY	$ 59,889	COMPANY SCH. B-5, PG. 1
11	FUEL - NUCLEAR, NET PER RUCO	59,889	COMPANY SCH. E-1, PG. 1
12	FUEL - NUCLEAR, NET ADJUSTMENT	$ -	LINE 10 - LINE 11
13	PREPAYMENTS PER COMPANY	$ 5,517	COMPANY SCH. B-5, PG. 1
14	PREPAYMENTS PER RUCO	5,517	COMPANY SCH. B-5, PG. 1
15	PREPAYMENTS ADJUSTMENT	$ -	LINE 11 - LINE 10
16	TOTAL WORKING CAPITAL ADJUSTMENT	$ (78,205)	SUM OF LINES 3, 6, 9, 12 & 15

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CASH WORKING CAPITAL LEAD/LAG CALCULATION

LINE NO.	DESCRIPTION	(A) TOTAL EXPENSES COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED EXPENSES	(D) REVENUE LAG DAYS	(E) EXPENSE LAG DAYS	(F) NET LAG DAYS	(G) CWC FACTOR	(H) WORKING CAPITAL REQUIREMENT
1	FUEL FOR ELECTRIC GENERATION:								
2	COAL	$ 200,856,342	$ -	$ 200,856,342	36.9503	32.3633	4.5869	0.0126	$ 2,524,764
3	NATURAL GAS	237,557,927		237,557,927	36.9503	44.2586	(7.3083)	(0.0200)	(4,755,910)
4	FUEL OIL	1,077,082	-	1,077,082	36.9503	32.3406	4.6097	0.0126	13,604
5	NUCLEAR:								
6	AMORTIZATION	34,445,413	-	34,445,413	36.9503	0.0000	36.9503	0.1012	3,486,909
7	SPENT FUEL	7,336,099	-	7,336,099	36.9503	76.3536	(39.4033)	(0.1080)	(791,932)
8	TOTAL	$ 481,272,863	$ -	$ 481,272,863					$ 477,435
9	PURCHASED POWER	$ 1,313,764,296	$ -	$ 1,313,764,296	36.9503	38.1502	(1.1999)	(0.0033)	$ (4,322,285)
10	TRANSMISSION BY OTHERS	14,391,245		14,391,245	36.9503	33.6939	3.2564	0.0089	128,370
11	TOTAL	$ 1,328,155,541	$ -	$ 1,328,155,541					$ (4,193,915)
12	OTHER OPERATIONS & MAINTENANCE:								
13	PAYROLL	$ 240,714,447	$ (47,868,000)	$ 192,846,447	36.9503	15.0019	21.9484	0.0601	$ 11,595,857
14	INCENTIVE	8,653,091	(4,563,000)	4,090,091	36.9503	214.5000	(177.5497)	(0.4864)	(1,989,584)
15	PENSION AND OPEB	38,986,000		38,986,000	36.9503	77.7100	(40.7597)	(0.1117)	(4,353,567)
16	EMPLOYEE BENEFITS	26,995,515		26,995,515	36.9503	20.3590	16.5913	0.0455	1,227,216
17	PAYROLL TAXES	18,118,131		18,118,131	36.9503	21.7859	15.1644	0.0416	752,808
18	MATERIALS & SUPPLIES	53,466,114		53,466,114	36.9503	24.2200	12.7303	0.0349	1,864,898
19	FRANCHISE PAYMENTS	11,986,402		11,986,402	36.9503	52.8397	(15.8894)	(0.0435)	(521,768)
20	VEHICLE LEASE PAYMENTS	3,169,771		3,169,771	36.9503	7.4379	29.5124	0.0809	256,308
21	RENTS	6,776,038		6,776,038	36.9503	(33.4860)	70.4363	0.1930	1,307,640
22	PALO VERDE LEASE	45,900,681		45,900,681	36.9503	47.3185	(10.3682)	(0.0284)	(1,304,038)
23	PALO VERDE SALE/LOSS GAIN AMORT.	(4,575,722)		(4,575,722)	36.9503	0.0000	36.9503	0.1012	(463,200)
24	INSURANCE	4,639,562		4,639,562	36.9503	0.0000	36.9503	0.1012	469,663
25	OTHER	119,131,971	(31,990,970)	87,141,001	36.9503	35.3900	1.5603	0.0043	372,092
26	TOTAL	$ 573,962,001	$ (84,421,970)	$ 489,540,031					$ 9,214,325
27	DEPRECIATION & AMORTIZATION	$ 321,525,565	$ (8,372,084)	$ 313,153,481	0.0000	0.0000	0.0000	0.0000	$ -
28	AMORT. OF ELECTRIC PLANT ACQ. ADJ.			-	0.0000	0.0000	0.0000	0.0000	-
29	AMORT. OF PROP. LOSSES & REG. STUDY COSTS	(2,564,492)		(2,564,492)	0.0000	0.0000	0.0000	0.0000	-
30	TOTAL	$ 318,961,073	$ (8,372,084)	$ 310,588,989					$ -
31	INCOME TAXES:								
32	CURRENT:								
33	FEDERAL & STATE	$ 76,203,614	$ 56,054,763	$ 132,258,377	36.9503	58.9500	(21.9997)	(0.0603)	$ (7,971,212)
34	DEFERRED	77,758,889		77,758,889	0.0000	0.0000	0.0000	0.0000	-
35	TOTAL	$ 153,962,503	$ 56,054,763	$ 210,017,266					$ (7,971,212)
36	OTHER TAXES:								
37	PROPERTY TAXES	$ 123,403,653	$ (5,976,591)	$ 117,427,062	36.9503	211.9422	(174.9920)	(0.4794)	$ (56,298,056)
38	SALES TAXES	158,240,555		158,240,555	16.6962	40.2100	(23.5139)	(0.0644)	(10,193,857)
39	FRANCHISE TAXES	18,920,381		18,920,381	16.6962	52.8397	(36.1435)	(0.0990)	(1,873,496)
40	TOTAL	$ 300,564,589	$ (5,976,591)	$ 275,667,617					$ (68,365,409)
41	INTEREST EXPENSE	$0	$ 89,343,046	$ 89,343,046	36.9503	186.0888	(149.1385)	(0.4086)	(36,505,568)
	TOTAL	$ 3,156,878,570	$ 46,627,164	$ 3,184,585,353					$ (107,344,345)

REFERENCES:
COLUMN (A): ATTACHMENT FB-1
COLUMN (B): SUM OF RELEVANT OPERATING ADJUSTMENTS IN RUCO SCHEDULE MDC-5, PAGES 1 AND 2
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): ATTACHMENT FB-1
COLUMN (E): ATTACHMENT FB-1, SCH. MDC- , PG.
COLUMN (F): COLUMN (D) - COLUMN (E)
COLUMN (G): COLUMN (F) ÷ 365 DAYS
COLUMN (H): COLUMN (C) x COLUMN (G)

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING INCOME - TEST YEAR AND RUCO PROPOSED (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-6

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO TEST YEAR AS ADJUSTED TOTAL COMPANY	(D) RUCO TEST YEAR AS ADJUSTED ACC JURISDICTION	(E) RUCO PROPOSED CHANGES ACC JURISDICTION	(F) RUCO RECOMMENDED ACC JURISDICTION
1	ELECTRIC OPERATING REVENUES	**$ 3,509,720**	**$ 4,907**	**$ 3,514,627**	**$ 3,445,400**	**$ 232,297**	**$ 3,677,697**
	OPERATING EXPENSES:						
2	PURCHASED POWER AND FUEL	$ 2,174,283	$ -	$ 2,174,283	$ 2,129,741	$ -	$ 2,129,741
3	OPERATIONS AND MAINTENANCE	684,209	(83,446)	600,763	672,765	-	672,765
4	DEPRECIATION AND AMORTIZATION	344,690	(8,372)	336,318	299,532	-	299,532
5	INCOME TAXES	9,952		(a)	41,546	90,713	132,258
6	OTHER TAXES	141,839	(5,977)	135,862	116,237	-	116,237
7	TOTAL	**$ 3,354,973**	**$ (64,976)**	**$ 3,289,997**	**$ 3,259,820**	**$ 90,713**	**$ 3,350,533**
8	OPERATING INCOME	**$ 154,747**	**$ 69,883**	**$ 224,630**	**$ 185,580**	**$ 141,584**	**$ 327,164**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C-1
COLUMN (B): SCHEDULE MDC-7
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (E) x APPROPRIATE JURISDICTIONAL FACTOR
COLUMN (E): SCHEDULE MDC-1
COLUMN (F): COLUMN (D) + COLUMN (E)

NOTES
(a) EXCLUDES INCOME TAXES

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED TOTAL COMPANY	(B) ADJ. #1	(C) ADJ. #2	(D) ADJ. #3	(E) ADJ. #4	(F) ADJ. #5	(G) ADJ. #6	(H) ADJ. #7	(I) ADJ. #8	(J) ADJ. #9
1	ELECTRIC OPERATING REVENUES	$ 3,509,720	$ -	$ -	$ 4,907	$ -	$ -	$ -	$ -	$ -	$ -
	OPERATING EXPENSES:										
2	PURCHASED POWER AND FUEL	$ 2,174,283									
3	OPERATIONS AND MAINTENANCE	684,209	(5,098)	976		(43,695)	(4,173)		(2,273)	(5,768)	(1,225)
4	DEPRECIATION AND AMORTIZATION	344,690						(715)			
5	INCOME TAXES	9,952									
6	OTHER TAXES	141,839									
7	TOTAL	$ 3,354,973	$ (5,098)	$ 976	$ -	$ (43,695)	$ (4,173)	$ (715)	$ (2,273)	$ (5,768)	$ (1,225)
8	OPERATING INCOME	$ 154,747	$ 5,098	$ (976)	$ 4,907	$ 43,695	$ 4,173	$ 715	$ 2,273	$ 5,768	$ 1,225

ADJUSTMENT #:		REFERENCE:
1	REMOVE OUT OF PERIOD PWEC A&G	TESTIMONY - DIAZ CORTEZ
2	INTEREST ON CUSTOMER DEPOSITS	SCHEDULE WAR-1
3	REMOVE DSM NET LOST REVENUES ADJUSTMENT	TESTIMONY - DIAZ CORTEZ
4	PENSION LIABILITY	TESTIMONY - DIAZ CORTEZ
5	REMOVE SERP EXPENSE	TESTIMONY - DIAZ CORTEZ
6	DECOMMISSIONING EXPENSE	SCHEDULE MDC-8
7	AMORTIZATION OF BARK BEETLE REGULATORY ASSET	SCHEDULE WAR-2
8	PWEC O&M	TESTIMONY - SCHLISSEL
9	TAX CONSULTING FEES	TESTIMONY - DIAZ CORTEZ

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-7
PAGE 2 OF 2

LINE NO.	DESCRIPTION	(K) ADJ. #10	(L) ADJ. #11	(M) ADJ. #12	(N) ADJ. #13	(O) ADJ. #14	(P) ADJ. #15	(Q) ADJ. #16	(R) ADJ. #17	(S) ADJ. #18	(T) ADJ. #19	(U) RUCO ADJUSTED TOTAL COMPANY
1	ELECTRIC OPERATING REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,514,627
	OPERATING EXPENSES:											
2	PURCHASED POWER AND FUEL											2,174,283
3	OPERATIONS AND MAINTENANCE		(566)	(15,149)	(786)		(4,563)	(1,122)		(5)		600,763
4	DEPRECIATION AND AMORTIZATION	(666)				(6,991)						336,318
5	INCOME TAXES										31,594	41,546
6	OTHER TAXES								(5,977)			135,862
7	TOTAL	$ (666)	$ (566)	$ (15,149)	$ (786)	$ (6,991)	$ (4,563)	$ (1,122)	$ (5,977)	$ (5)	$ 31,594	$ 3,288,772
8	OPERATING INCOME	$ 666	$ 566	$ 15,149	$ 786	$ 6,991	$ 4,563	$ 1,122	$ 5,977	$ 5	$ (31,594)	$ 225,855

ADJUSTMENT #:		REFERENCE:
10	DEPRECIATION EXPENSE	SCHEDULE WAR-3
11	MISCELLANEOUS EXPENSES	SCHEDULE MDC-9
12	REMOVE UNREGULATED OPERATIONS	TESTIMONY - DIAZ CORTEZ
13	LOBBYING & POLITICAL ACTIVITIES EXPENSE	SCHEDULE MDC-10
14	AMORTIZATION EXPENSE	SCHEDULE MDC-11
15	REDUCE INCENTIVE PAY	TESTIMONY - RIGSBY
16	SUNDANCE O&M	TESTIMONY - SCHLISSEL
17	PROPERTY TAX EXPENSE	TESTIMONY - RIGSBY
18	ADVERTISING EXPENSE	TESTIMONY - RIGSBY
19	INCOME TAX EXPENSE	SCHEDULE WAR-3

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING ADJUSTMENT #6 - DECOMMISSIONING EXPENSE

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-8

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	DECOMMISSION ING EXPENSE PER PRIOR ORDER	$19,211,000	DECISION NO. 67744
2	T/Y RECORDED DECOMMISSIONING EDXPENSE	16,093,000	RUCO DR# 2-9
3	REQUIRED ADJUSTMENT TO T/Y	3,118,000	LINE 1 - LINE 2
4	ADJUSTMENT PER COMPANY	3,833,000	COMPANY WP LLR_WP15, PAGE 1
5	ADJUSTMENT	($715,000)	LINE 3 - LINE 4

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING ADJUSTMENT #11 -MISCELLANEOUS EXPENSES

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-9

LINE NO.	DESCRIPTION	AMOUNT	ACCT #
	SPONSORSHIPS		
1	DODGE THEATRE	$100,000	913
2	SCHOOL RECOGNITION PROGRAM	15,000	909
3	NATIONAL NITE OUT	1,964	909
4	AAED PREMIER PARTNERSHIP	6,000	909
5	PEORIA GAIN EVENTS	1,500	909
6	NATIONAL FUEL FUNDS NETWORK	1,000	909
7	FORECASTERS CLUB - BISBEE & DOUGLAS	2,000	909
8	25th ANNIVERSARY OOPS SPONSORSHIP	5,025	913
9	TEACHERS WORKSHOPS	2,700	909
10	GREATER PHOENIX CHAMBER OF COMMERCE	12,188	930.2
11	SUBTOTAL - SPONSORSHIPS	147,377	
	ITEMS NOT NEEDED TO PROVIDE ELECTRIC SERVICE		
12	LIGHT-UP MARTINI GLASSES	$2,498	909
13	STROBE LIGHTS, BALLONS, FISBEES, ETC.	4,131	909
14	NLIEC TUESDAY RECEPTION	2,500	909
15	CONTRIBUTION - EITC HOTLINE	1,500	909
16	PARTY SUPPLIES - CANOPY, WATER BARRELS, ETC.	3,364	930.2
17	LEVY'S RESTURANT - DODGE THEATRE	3,195	909
18	BOBBLEHEADS	990	909
19	CATERED LUNCHES	400,000	
19	SUBTOTAL - UNNECESSARY ITEMS	418,178	
20	TOTAL MISC. ADJUSTMENT	$565,555	

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING ADJUSTMENT #13 - LOBBYING EXPENSE

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-10

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	FEDERAL AFFAIRS - LOBBYING EXPENSE	$137,686	DR UTI-10-305
2	FEDERAL AFFAIRS - OTHER GENERAL - 50%	348,315	DR UTI-10-305
3	PUBLIC AFFAIRS - PAYROLL - 50%	299,655	DR UTI-10-306
4	TOTAL ADJUSTMENT	$785,655	SUM LINES 1 THROUGH 3

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING ADJUSTMENT #14 - AMORTIZATION EXPENSE

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-11

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	T/Y INCREASE IN INTANGIBLE & GENERAL PLANT	5.42%	SCHEDULE E-5
2	COMPOSITE DEPRECIATION RATE	10.38%	DR RUCO 11.4c
3	INCREASE IN INTANGIBLE & GENERAL PLANT VALUE	29,000,000	DR RUCO 11.4c
4	INCREASE IN AMORTIZATION EXPENSE	3,011,057	LINE 3 x LINE 2
5	COMPANY REQUESTED INCREASE IN AMORTIZATION EXPENSE	10,002,422	LLR_WP19, PG. 5
6	DECREASE IN AMORTIZATION EXPENSE	($6,991,365)	LINE 5 - LINE 5

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
COST OF CAPITAL

DOCKET NO. E-01345A-05-0816
SCHEDULE MDC-12

LINE NO.	TYPE OF CAPITAL	(A) PERCENT	(B) COST RATE	(C) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	50.00%	9.25%	4.63%
2	TOTAL DEBT	50.00%	5.41%	2.71%
3	TOTALS	100.00%		7.33%

PRE-TAX INTEREST COVERAGE = 3.85X (a)

REFERENCES:
COLUMN (A): TESTIMONY - HILL
COLUMN (B): TESTIMONY - HILL
COLUMN (C): COLUMN (A) x COLUMN (B)

NOTE:
(a) ASSUMING THE COMPANY EXPERIENCES, PROSPECTIVELY, AN INCOME TAX RATE OF 40.00%, THE PRE-TAX OVERALL RETURN WOULD BE 10.41% [7.33% - (2.71%) = 4.63% / (1 - 40.00%) = 7.71% + (2.71%)]. THAT PRE-TAX OVERALL RETURN (10.41%) DIVIDED BY THE WEIGHTED COST OF DEBT (2.71%), INDICATES A PRE-TAX INTEREST COVERAGE OF 3.85 TIMES.

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. Earlier this year I was awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

…

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Arizona Public Service Company's ("APS" or "Company") application for a permanent rate increase ("Application"). APS filed an amended application with the Commission on January 31, 2006. The Company is using the one-year operating period ended September 30, 2005 as the test year in this proceeding.

Q. What aspects of the APS Application will you provide direct testimony on?

A. My direct testimony will concentrate on the Company's rate base adjustment for the bark beetle regulatory asset and on various operating expense adjustments.

Q. Which other RUCO witnesses will be providing direct testimony in this proceeding?

A. Ms. Marylee Diaz-Cortez, CPA, the chief of RUCO's Accounting & Rates section, will provide direct testimony on the majority of the rate base issues addressed in the Company's Application and on the operating adjustments proposed by APS that are not addressed in my testimony.

In addition to the direct testimony of Ms. Diaz Cortez, RUCO will also present the testimony of three outside consultants: Mr. David A. Schlissel, a senior consultant with Synapse Energy Economics, who will present testimony on the fuel, purchased power and generation issues associated with the case; Mr. J. Richard Hornby, also a senior consultant with Synapse Energy Economics, who will present testimony on APS' hedging program; and Mr. Stephen G. Hill, principal of Hill Associates, who will address the cost of capital issues and will present his recommended rate of return on invested capital which will include his recommended weighted costs of common equity and debt.

Q. Please describe how you conducted your analysis of the APS Application.

A. I reviewed the APS Application and analyzed various work papers that were provided to RUCO by the Company as part of its amended filing. Other pertinent information and source documents were collected through a series of written data requests, which were faxed and mailed to the Company. After compiling the aforementioned information and materials, I performed an analysis that provided additional insight into the Company's working capital and operating expense proposals. RUCO's recommendations on the rate base portion of the bark beetle regulatory asset and the seven operating expense adjustments covered in this testimony are based on the results of my analysis.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-3. These schedules exhibit detailed information on RUCO's Rate Base Adjustment #3 and

Operating Adjustments #2, #7, #10, #15 and #17 through #19. The effects of these specific adjustments on RUCO's recommended levels of rate base and operating expense can be viewed in Schedules MDC-2 and MDC-6, which are presented in the direct testimony of RUCO witness Marylee Diaz Cortez, CPA.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you address in your testimony that pertain to rate base, operating revenue, and operating expense.

A. My testimony will present the following recommended adjustments:

Rate Base Adjustments:

Bark Beetle Regulatory Asset – This adjustment reverses the Company's $6,115,000 pro-forma increase to the level of deferred costs associated with bark beetle remediation that are included in rate base.

Operating Expense Adjustments:

Interest on Customer Deposits – This adjustment increases the level of interest paid on customer deposits by $976,000. The adjustment reflects RUCO's use of an updated one-year constant maturities rate that APS uses to calculate levels of interest expense on the Company's year-end balance of customer deposits.

Amortization of Bark Beetle Regulatory Asset – This adjustment reduces the Company-proposed level of bark beetle remediation expense by $2,273,000. The adjustment reduces the Company recommended estimated level of expense to a level that reflects a three year amortization of the actual amount of deferred costs associated with bark beetle remediation that are included in rate base.

Depreciation Expense – This adjustment restates the Company-proposed level of depreciation expense to reflect the level of plant-in-service being recommended by RUCO witness Diaz Cortez.

Reduce Incentive Pay – This pro-forma adjustment reduces the Company's test year-level of expensed incentive program costs by $4,163,000.

Property Tax Expense – This adjustment reduces the Company's property tax expense liability by $5,976,491. The adjustment reflects the temporary suspension of the county education tax rate provided by H.B. 2876 which was signed into law during the recent legislative session.

Advertising Expense – This adjustment reduces APS' advertising expense by $4,625. The adjustment removes promotional advertising that touts the Company's community service activities.

<u>Income Tax Expense</u> – This adjustment calculates the appropriate level of income tax expense given RUCO's recommended operating income.

OVERVIEW OF THE FILING

Q. Briefly describe APS' rate application and any pertinent events that have occurred since the Company's original filing date.

A. APS is seeking an increase of $449.6 million in base rates, or a 21.1 percent increase on average, for the Company's jurisdictional electric operations. APS filed its original application on November 4, 2005 using a test year ended December 31, 2004. After discussions with ACC Staff, APS agreed to file an amended application containing updated operating information on certain generation facilities that were either included in rate base as a result of the Company's prior rate case settlement agreement[1] (i.e. the former generation assets of Pinnacle West Energy Corporation) or were acquired on the open market during 2005 (i.e. the Company's Sundance generation facility purchased from PPL Sundance Energy, LLC). On January 31, 2006, APS filed an amended application, the subject of this proceeding, which contains information on a test year ended September 30, 2005.

On January 6, 2006, APS filed an application with the Arizona Corporation Commission ("ACC" or "Commission") for an emergency interim rate

[1] Decision No. 67744, Dated April 7, 2005

increase and for an interim amendment to Decision No. 67744, dated April 7, 2005. In that proceeding APS sought an interim 14 percent increase over the Company's base rates, which were authorized in Decision No. 67744.

On May 2, 2006, the ACC passed an amended order[2], which rejected APS' argument that an emergency existed and implemented an interim adjustor mechanism, effective May 1, 2006, that would allow APS to recover purchased power and fuel costs (with the exception of unplanned outage costs) incurred during the 2006 operating period. Under the decision approved by the Commission, average residential bills will increase by $7.33 per month during the summer and by $4.74 during the winter over the life of the interim adjustor mechanism.

RATE BASE

Rate Base Adjustment #3 – Bark Beetle Regulatory Asset

Q. Please provide a brief background on the bark beetle remediation issue and explain the rationale for the Company's adjustments that involve cost recovery for APS' bark beetle remediation efforts.

A. Bark beetle remediation costs became an issue during APS' prior rate case filing and are specifically addressed in the settlement agreement approved in Decision No. 67744 ("Settlement Agreement"). Remediation

[2] Decision No. 68685, Dated May 5, 2006

costs have been incurred because of drought conditions that have created a bark beetle infestation resulting in dead and dying trees around the Company's transmission and distribution lines located in the state's forested areas. The Commission authorized APS to defer, for latter recovery, the reasonable and prudent direct costs of bark beetle remediation that exceed the Company's test year levels of tree and brush control. According to the provisions of the Settlement Agreement, the Commission would determine the reasonableness, prudence, and allocation of the costs of bark beetle remediation, and determine the appropriate amortization period in the Company's next rate case.

Q. Have you analyzed the Company's adjustments for bark beetle infestation?

A. Yes.

Q. Please describe the Company's adjustments related to bark beetle infestation.

A. The Company has made two pro-forma adjustments for the purpose of recovering the costs associated with bark beetle infestation. The first adjustment is a $6,115,000 increase to the test year-end deferral balance of $4,469,059. APS proposes to include the adjusted deferral balance in rate base and to earn a return on the regulatory asset. Second, APS proposes to recover the deferred costs over a three-year amortization period. The second adjustment, which I will discuss in the next section of my testimony, increases test year operating expenses associated with bark beetle remediation.

Q. Do you agree with APS' first adjustment, which increases the amount of the bark beetle regulatory asset by $6,115,000?

A. No. I am recommending that the Commission reject the APS adjustment, which increases the amount of the bark beetle regulatory asset by $6,115,000. Consequently, I have removed the Company-proposed adjustment from rate base.

Q. Please explain why you believe the Commission should reject the Company-proposed adjustment to the bark beetle regulatory asset.

A. As can be seen in APS witness Laura Rockenberger's work paper labeled LLR_WP2, page 7 of 70, the Company's adjustment is only an estimate of what the deferred costs will be in January 2007 as opposed to the actual direct costs that were recorded at the end of the test year. Because the adjustment is only an estimate of what the amount of the regulatory asset may be at some future point in time, the adjustment fails the known and measurable test. The adjustment also violates the matching principle from the standpoint that no actual recorded expenses are associated with the estimate. In this respect the Company-proposed adjustment is akin to an adjustment for post-test year plant. For these reasons, I believe the

Commission should reject the Company-proposed adjustment, and only allow APS to recover and earn a return on the actual $4,469,059 in deferred costs that were recorded at the end of the test year.

OPERATING INCOME

Operating Adjustment #2 – Interest on Customer Deposits

Q. How does APS calculate interest on customer deposits held by the Company?

A. APS calculates interest on customer deposits by multiplying the year-end customer deposit balance by a one-year treasury constant maturities rate. The one-year constant maturities rate used by the Company is the daily rate that is published in the Federal Reserve's website on the first business day of the New Year. In this proceeding, APS used the customer deposit balance booked on the last day of the test year and the 2.79 percent one-year constant maturities rate published on January 3, 2005. The Company stated in its application that this is the same method that has been used by the Commission in prior rate case proceedings.

Q. Has RUCO made an adjustment for interest on customer deposits?

A. Yes. RUCO is recommending that the level of interest on customer deposits be increased by $976,000. The adjustment reflects a known and measurable change and can be seen in Schedule WAR-1.

Q. How did you determine your recommended level of interest on customer deposits?

A. I multiplied the customer deposit balance, that was booked on September 30 of the test year, times the updated one-year constant maturities rate that appeared on the Federal Reserve's website. The rate, listed for January 3, 2006, is 4.38 percent, or 159 basis points[3] higher than the 2.79 percent January 3, 2005 rate used in the Company's application. The 4.38 percent rate that I used was the most up-to-date figure available prior to the Commission-ordered filing deadline for direct testimony. The next Federal Reserve update that will display an actual rate for January 2, 2007 will not be posted until January 9, 2007.

Operating Adjustment #7 – Amortization of Bark Beetle Regulatory Asset

Q. Do you agree with the Company-proposed three-year amortization period for recovery of the bark beetle regulatory asset in rates?

A. Yes. I believe that three years is an appropriate amortization period that reflects a reasonable period of time between rate case filings. If bark beetle infestation continues to be a problem during the Company's next rate case filing, the Commission can allow APS to continue to defer the costs associated with bark beetle remediation.

[3] 100 basis points are equal to 1.00 percent.

Q. Do you agree with the Company's methodology for calculating the amortization of the bark beetle regulatory asset?

A. No. APS used the same methodology that it used to calculate the Company's adjustment for the bark beetle regulatory asset included in rate base. The Company's adjustment is only an estimate of what the bark beetle remediation costs will be in January 2007 as opposed to a three-year amortization of the actual direct costs that were recorded at the end of the test year. For the above reasons, I believe the Commission should reject the Company-proposed adjustment, and only allow a three-year amortization of the $4,469,059 (consistent with my rate base recommendation) in deferred costs that were recorded at the end of the test year.

Q. Does RUCO's adjustment allow APS to recover the bark beetle regulatory asset over a three-year period?

A. Yes. As can be seen on schedule WAR-2, I have calculated the appropriate level of amortization expense for RUCO's adjusted bark beetle regulatory asset amount. I then reversed the Company's adjustment and removed the October through December 2005 bark beetle costs that were part of the Company's calculation. My adjustment will allow the Company to recover $1,490,000 or approximately one third of the $4,469,000 bark beetle regulatory asset.

Operating Adjustment #10 – Depreciation Expense

Q. Please explain your adjustment to depreciation expense?

A. My adjustment removes depreciation expense associated with $36,684,000 in retired plant assets. This includes retired reactor plant equipment valued at $27,453,000 (depreciated at a rate of 1.47 percent) and retired turbo-generator units valued at $9,231,000 (depreciated at a rate of 2.84 percent). The adjustment restates the Company-proposed level of depreciation expense to reflect the level of plant-in-service being recommended by RUCO witness Diaz Cortez.

Operating Adjustment #15 – Reduce Incentive Pay

Q. Why has RUCO reduced APS' expensed incentive program costs by $4,563,000?

A. RUCO believes that a reduction of approximately twenty percent to the Company's incentive program is warranted given the amount of the rate increase that APS is seeking in this case. RUCO recommends this figure as a possible starting point for any specific level of reduction that the Commission may want to order in this case.

Q. Please explain the rationale for the reduction that RUCO is proposing.

A. RUCO believes that it is simply not fair for APS ratepayers to have to shoulder the burden of higher electric rates when APS employees are given an opportunity to earn more pay that could mitigate or eliminate the impact of their employer's rate increase on them personally. Many of APS' customers will not have the opportunity to earn more money to make up for what they will lose as a result of higher electric bills. This not only includes low income and elderly ratepayers, but other types of working individuals who are forced to live on fixed monthly incomes. Not everyone in the workplace is employed by a company that offer incentives or bonuses that give their workers the opportunity to earn more than what is included in their regular monthly wages and salaries. Not every business offers employees the chance to work more hours a week to make up the difference in lost income that results from higher monthly electric rates. Under APS' proposal, a customer on a levelized billing plan would see his or her rates increase by approximately $20.00 per month. For many working individuals, the rate increase being proposed by APS will mean one less movie that they can take their family members to see each month, or one less sporting event that they can attend, perhaps one less dinner out, maybe one less concert or one less trip to a bowling center. RUCO believes that this is a lot to ask of many working families who have already had to forgo simple entertainment or basic living choices because of recent increases in natural gas and gasoline prices. RUCO also believes that, given the fact that ratepayers have to sacrifice their own simple pleasures in order endure these types of increases in their cost of living, it is only just and reasonable that APS employees share the same pain and hardship that their employer's rate increase will have on their customers.

Q. Did RUCO recommend a reduction for incentive pay in the Company's prior rate case that ended in a settlement agreement?

A. Yes. In the prior rate case RUCO recommended, in its direct testimony, that the Company's incentive program be eliminated completely. Even though APS employees had not attained the goals that were set for them by the Company, they still received incentive pay. The Company stated at that time that even though the employee efforts fell far short of the earnings threshold levels established in the plan, the Company's board of directors elected to pay out a bonus anyway. Given the circumstances, RUCO believed at that time that the payment of bonuses should not be recovered from ratepayers.

Q. What was ACC Staff's position on incentive pay during the prior rate case proceeding for APS?

A. The consultant for ACC Staff recommended that APS officers should not receive incentive compensation but believed that management and rank and file employees should continue to receive incentive pay. However, It should be pointed out that Arizonans were not paying an average of $3.00 a gallon for gasoline or facing the prospect of slower economic growth as they are now. In the Company's recent emergency rate case hearing, local economist Elliot Pollack testified that the time to implement a rate increase is during an economic upswing. Given the recent economic outlook for slower growth, it would appear that this might not be the time to implement the amount of increase that APS is seeking in this case.

Q. So RUCO is only seeking a reduction in incentive pay as opposed to the complete elimination of incentive pay for APS employees?

A. Yes. That is correct. Under RUCO's recommendation, APS employees, other than Company officers, would still be able to earn incentive pay at a reduced level from prior periods. Unlike in the prior case, the majority of the incentive goals were achieved. In better economic times RUCO might not take such a position regarding a fairly administered incentive pay plan that rewards employees for achieving the goals set before them. However, given the current circumstances, RUCO believes that it is only fair that everyone – ratepayers, Company officers, Company management, and the Company's rank and file employees – should all help shoulder the burden of the rate increase being proposed by APS.

Q. Does RUCO recognize that the ACC might want to adjust the Company's incentive pay by some amount other that what RUCO has recommended?

A. RUCO understands that the ACC Commissioners will be the ones to make the ultimate decision on how much, if any, the Company's incentive pay will be reduced. Because of this, RUCO has not attempted to tie its

$4,563,000 recommended adjustment to a specific formula or calculation. However, for the reasons stated earlier, RUCO believes that it is only fair that the pain of increased energy costs should be borne not only by ratepayers, but shared by the Company as well.

Operating Adjustment #17 – Property Tax Expense

Q. Please describe your adjustment to property tax expense.

A. The adjustment reduces the Company-proposed level of property tax by $5,976,491 and reflects the temporary suspension of the county education tax rate provided by H.B. 2876, which was signed into law during the recent legislative session. The change in the Company's property tax liability will be recognized on APS' next property tax bill in September 2006 so the effect of the change will be included in the Company's new rates[4].

Q. How did RUCO arrive its property tax adjustment figure?

A. RUCO's property tax adjustment figure was obtained from APS in the Company's response to RUCO data request 11.2. The adjustment represents the difference between the Company's original property tax figure and the APS adjusted pro-forma O&M property tax figure provided in the Company's response to RUCO data request 11.2. The Company's

[4] Because electric company property taxes are assessed on plant value, as opposed to revenues as are water company property taxes, there is no lag in the period in which the full impact of increases or decreases are realized.

original normalized pro-forma O&M property tax figure was verified before making the adjustment.

Operating Adjustment #18 – Advertising Expense

Q. Did RUCO's audit of APS focus specific attention to the Company's advertising expense as a result of concerns raised during APS' recent emergency rate case proceeding?

A. Yes. During the Company's emergency rate case proceeding, several Commissioners expressed their concerns regarding above-the-line expenditures for such things as advertising and sponsorships for local professional sports teams. During RUCO's audit of APS, particular attention was paid to accounts where the aforementioned expenditures would have been recorded. The Company provided RUCO with a sample of invoices for television and print media advertising during the test year that were recorded in Company Account 9120.

Q. Has APS made adjustments to remove these types of above-the-line expenses in the Company's Application?

A. Yes. APS made a $6 million adjustment to remove professional sports team sponsorships and to remove "brand" advertising that promoted APS as a company as opposed to advertising that promoted safety and conservation of energy. RUCO specifically targeted these types of expenditures in its audit and had the opportunity to view actual invoices during an on site visit to APS' offices in downtown Phoenix.

Q. Is any additional adjustment necessary for advertising expense?

A. Yes. I have made an adjustment to reduce APS' advertising expense by $4,625. The adjustment removes promotional advertising, discovered during RUCO's audit visit to APS, which touted the Company's community service efforts. The advertisement appeared in local print media during the test year. RUCO believed that this type of advertising fell into the category of promotional advertising, which is similar to the branding campaign ads that APS removed from the Company's advertising expense.

Operating Adjustment #19 – Income Tax Expense

Q. Have you calculated an appropriate level of income tax expense based on RUCO's recommended adjusted operating income for APS?

A. Yes I have. My adjustment for income tax expense is exhibited in Schedule WAR-3.

...

Q. Does your calculation of income tax expense use the synchronized interest methodology to determine the amount of interest expense to be deducted from income tax?

A. Yes it does. The interest synchronization portion of my income tax liability calculation appears in Note (a) on Schedule WAR-3. The calculation multiplies RUCO witness Diaz Cortez's recommended level of rate base times RUCO witness Hill's recommended weighted cost of debt.

Q. Does your silence on any of the issues or matters addressed in the Company's Application constitute either your, or RUCO's, acceptance of the Company's position on such issues or matters?

A. No, it does not.

Q. Does this conclude your testimony on APS?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816
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SCHEDULE #

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING INCOME ADJUSTMENT #2 - INTEREST ON CUSTOMER DEPOSITS (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE WAR-1

LINE NO.	DESCRIPTION	(A) PER COMPANY WORKPAPER		(B) PER RUCO AUDIT	(C) DIFFERENCE
1	CUSTOMER DEPOSIT BALANCE (SEPTEMBER 30, 2005)	$ 54,800		$ 57,192	$ 2,392
2	TIMES: CONSTANT MATURITY RATE ON 1-YEAR U.S. TREASURY SECURITY	2.79%	(a)	4.38%	1.59%
3	TOTAL INTEREST EXPENSE ON CUSTOMER DEPOSITS	$ 1,529		$ 2,505	
4	RUCO ADJUSTMENT				$ 976

REFERENCES:
COLUMN (A): LINE 1 - COMPANY WORKPAPER CNF_WP9
COLUMN (B): LINE 1 - COMPANY WORKPAPER CNF_WP9
COLUMN (B): LINE 2 - FEDERAL RESERVE WEBSITE – ONE-YEAR CONSTANT MATURITIES RATE ON JANUARY 3, 2006
COLUMN (B): LINE 1 - COMPANY RESPONSE TO DATA REQUEST UTI 1-60
COLUMN (C): COLUMN (B) - COLUMN (A)

NOTES
(a) PER APS WITNESS FROGGATT DIRECT TESTIMONY (PAGE 13, LINES 10 THRU 12):
ONE-YEAR TREASURY CONSTANT MATURITIES RATE EFFECTIVE THE FIRST BUSINESS DAY OF EACH YEAR AS PUBLISHED ON THE FEDERAL RESERVE WEBSITE

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING INCOME ADJUSTMENT #7 - AMORTIZATION OF BARK BEETLE REGULATORY ASSET (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE WAR-2

LINE NO.			
1	TOTAL DEFERRAL AT SEPTEMBER 30, 2005	$ 4,469	UTILITECH INC.'S DATA REQUEST UTI 14-351
2	3-YEAR AMORTIZARTION OF OF THE TOTAL DEFERRAL	$ 1,490	LINE 1 ÷ 3 YEARS
3	REVERSE COMPANY ADJUSTMENT	$ (1,438)	APS WORK PAPER LLR_WP24
4	REMOVE OCT-DEC 2004 BARK BEETLE COSTS	$ (2,325)	APS WORK PAPER LLR_WP24
5	RUCO ADJUSTMENT	$ (2,273)	SUM OF LINES 2, 3 AND 4

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED SEPTEMBER 30, 2005
OPERATING INCOME ADJUSTMENT #19 - INCOME TAXES (000'S)

DOCKET NO. E-01345A-05-0816
SCHEDULE WAR-3

LINE NO.	DESCRIPTION	JURISDICTIONAL AMOUNT	REFERENCE
	FEDERAL INCOME TAXES:		
1	OPERATING INCOME BEFORE INCOME TAXES	$ 227,126	SCH. MDC-6
	LESS:		
2	ARIZONA STATE TAX	6,628	LINE 11
3	INTEREST EXPENSE	120,734	NOTE (a)
4	FEDERAL TAXABLE INCOME	99,764	LINE 1 - LINES 2 & 3
5	FEDERAL INCOME TAX RATE	35.00%	TAX RATE
6	FEDERAL INCOME TAX EXPENSE	34,917	LINE 4 X LINE 5
	STATE INCOME TAXES:		
7	OPERATING INCOME BEFORE INCOME TAXES	227,126	LINE 1
	LESS:		
8	INTEREST EXPENSE	120,734	NOTE (a)
9	STATE TAXABLE INCOME	106,392	LINE 7 - LINE 8
10	STATE TAX RATE	6.230%	TAX RATE
11	STATE INCOME TAX EXPENSE	6,628	LINE 9 X LINE 10
12	TOTAL INCOME TAXES	41,546	LINE 6 + LINE 11
13	INCOME TAXES PER COMPANY	9,952	COMPANY SCH. C-1, PG. 1
14	ADJUSTMENT	$ 31,594	LINE 12 - LINE 13

NOTE (a)
INTEREST SYCHRONIZATION

ADJUSTED RATE BASE	$ 4,463,358
WEIGHTED COST OF DEBT	2.71%
INTEREST EXPENSE	$ 120,734

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

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DIRECT TESTIMONY

STEPHEN G. HILL

Docket No. E-01345A-05-0816

ARIZONA PUBLIC SERVICE COMPANY

INTRODUCTION / SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is Stephen G. Hill. I am self-employed as a financial consultant, and principal of Hill Associates, a consulting firm specializing in financial and economic issues in regulated industries. My business address is P.O. Box 587, Hurricane, West Virginia, 25526 (e-mail: sghill@compuserve.com).

Q. BRIEFLY, WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. After graduating with a Bachelor of Science degree in Chemical Engineering from Auburn University in Auburn, Alabama, I was awarded a scholarship to attend Tulane Graduate School of Business Administration at Tulane University in New Orleans, Louisiana. There I received a Master's Degree in Business Administration. I have been awarded the professional designation, "Certified Rate of Return Analyst," by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience and the successful completion of a comprehensive examination. I have also been selected to be on the Board of Directors of that national organization. A more detailed account of my educational background and occupational experience appears in Appendix A.

Q. HAVE YOU TESTIFIED BEFORE THIS OR OTHER REGULATORY COMMISSIONS?

A. Yes, I have appeared previously before this Commission. In addition, I have testified on cost of capital, corporate finance and capital market issues in more than 225 regulatory proceedings before the following regulatory bodies: the West Virginia Public Service Commission, the Pennsylvania Public Utilities Commission, the Oklahoma State Corporation Commission, the Public Utilities Commission of the State of California, the Texas Public Utilities Commission, the Maryland Public Service Commission, the Public Utilities Commission of the State of Minnesota, the Ohio Public Utilities Commission, the

Insurance Commissioner of the State of Texas, the North Carolina Insurance Commissioner, the Rhode Island Public Utilities Commission, the City Council of Austin, Texas, the Texas Railroad Commission, the Missouri Public Service Commission, the South Carolina Public Service Commission, the Public Utilities Commission of the State of Hawaii, the New Mexico Corporation Commission, the State of Washington Utilities and Transportation Commission, the Georgia Public Service Commission, the Public Service Commission of Utah, the Illinois Commerce Commission, the Kansas Corporation Commission, the Indiana Utility Regulatory Commission, the Virginia Corporation Commission, the Montana Public Service Commission, the Public Service Commission of the State of Maine, the Public Service Commission of Wisconsin, the Vermont Public Service Board, the Federal Communications Commission and the Federal Energy Regulatory Commission. I have also testified before the West Virginia Air Pollution Control Commission regarding appropriate pollution control technology and its financial impact on the company under review and have been an advisor to the trial Staff of this Commission on matters of utility finance.

O. ON BEHALF OF WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Residential Utility Consumer Office (RUCO).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony, I present the results of studies I have performed related to the establishment of an appropriate return on equity and overall cost of capital for the integrated electric utility operations of Arizona Public Service Company (APS, the Company), a subsidiary of Pinnacle West Capital Corporation (PNW, Pinnacle West, the Parent). In addition to my testimony regarding the Company's current cost of capital, I review the cost of capital testimony provided by Dr. William Avera and discuss certain aspects in his testimony that lead to an overstatement of the cost of equity capital.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, Exhibit_(SGH-1) consists of 13 Schedules and provides the analytical support for the conclusions reached regarding the overall cost of capital for Arizona Public Service Company presented in the body of the testimony. This Exhibit was prepared by me and is correct to the best of my knowledge and belief. Also, I have provided four Appendices ("A" through "D"), which contain additional detail regarding certain aspects of my narrative testimony in this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR ARIZONA PUBLIC SERVICE COMPANY'S ELECTRIC UTILITY OPERATIONS IN THIS PROCEEDING.

A. My testimony is organized into five sections. First, I discuss recent findings in the field of financial economics that are germane to the determination of the risk premium currently included in the cost of capital as well as other factors that support the reasonableness of single-digit cost of capital estimates. Second, I review the current economic environment in which my equity return estimate is made. Third, I review the capital structure requested by APS for ratemaking purposes in comparison to capital structures employed by the Company and its parent company historically, as well as capital structures prevalent in the energy utility industry. From that review, I develop a capital structure appropriate for ratemaking purposes.

Fourth, I evaluate the cost of equity capital for similar-risk utility operations using Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Modified Earnings-Price Ratio (MEPR), and Market-to-Book Ratio (MTB) analyses. Fifth, I comment on the pre-filed cost of capital testimony submitted by Company witness, Dr. William Avera.

I have estimated the equity capital cost of integrated electric utility companies to fall in a range of 9.25% to 9.75%. Within that range, I estimate the equity cost of the Company's electric utility operations to be at the lower end of a reasonable range of equity costs for electric utilities due to the Company's lower financial risk—9.25%.

Applying that 9.25% equity capital cost to a capital structure that is reasonable for ratemaking purposes, containing 50% common equity and 50% long-term debt, produces an overall cost of capital of 7.33% (Exhibit_(SGH-1), Schedule 13). That overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.85 times. That level of pre-tax coverage is well above the level of interest coverage actually achieved by APS over the past three years, which has averaged 2.94x.[1] Therefore, the capital structure and equity return I recommend is sufficient to support and improve the Company's financial position and fulfills the requirement of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation while maintaining the Company's ability to attract capital.

Q. WHY SHOULD THE COST OF CAPITAL SERVE AS A BASIS FOR THE PROPER ALLOWED RATE OF RETURN FOR A REGULATED FIRM?

A. The Supreme Court of the United States has established, as a guide to assessing an appropriate level of profitability for regulated operations, that investors in such firms are to be given an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in the unregulated sector for assuming the same degree of risk. The <u>Bluefield</u> and <u>Hope</u> cases provide the seminal decisions [<u>Bluefield Water Works v. PSC</u>, 262 US 679 (1923); <u>FPC v. Hope Natural Gas Company</u>, 320 US 591 (1944)]. These criteria were restated in the <u>Permian Basin Area Rate Cases</u>, 390 US 747 (1968). However, the Court also makes quite clear in <u>Hope</u> that regulation does not guarantee profitability and, in <u>Permian Basin</u>, that, while investor interests (profitability) are certainly pertinent to setting adequate rates, those interests do not exhaust the relevant considerations.

As a starting point in the rate-setting process, then, the cost of capital of a regulated firm represents the return investors could expect from other investments, while assuming no

[1] Arizona Public Service Company 2006 S.E.C. Form 10-Q, March 31, 2006, Exhibit 12.

more and no less risk. Since financial theory holds that investors will not provide capital for a particular investment unless that investment is expected to yield the opportunity cost of capital, the correspondence of the cost of capital with the Court's guidelines for appropriate earnings is clear.

I. INVESTOR RETURN EXPECTATIONS

Q. UTILITY EQUITY RETURN AWARDS IN THE U.S. OVER THE PAST YEAR HAVE AVERAGED ABOUT 10.5%. YOUR EQUITY RETURN RECOMMENDATION FOR APS IS BELOW RECENT ALLOWED RETURN AVERAGES. ARE THERE OBJECTIVE INDICATORS THAT SHOW YOUR ESTIMATE IS REASONABLE?

A. Yes, there is both theoretical and practical evidence, which shows that an equity return of 9.25% for an electric utility operation is not only reasonable, but may, in fact, be generous.

Perhaps the most compelling evidence that investor equity return expectations are likely to be <u>below</u> my estimate of the current cost of equity in this proceeding and far below average allowed returns for utilities is provided by the Company itself. In its 2005 S.E.C. Form 10-K, at page 99, Pinnacle West Corporation published data regarding the Company's pension plan and the expected return on the invested assets in that portfolio. The Company's published data indicate that it expects to earn a 9.00% return on its pension fund portfolio, comprised mostly of equity investments.

In response to RUCO Data Request 11.1, the Company provided support from its pension fund advisors (Towers Perrin) regarding the long-term equity return expectations that form the basis of the Company's expected retirement portfolio returns. The Company's pension plan advisor projects a long-term return for a diversified portfolio of common equities, based on an analysis of historical and projected data ranging from [redacted].[2] That equity return expectation is for common stocks, generally, not for utility stocks, which would have a lower equity return expectation due to their lower risk.

[2] Company response to RUCO 11.1, Towers Perrin, US Capital Market Assumptions for Asset/Liability Forecasting, APS 10620 [Data redacted. This page provided in confidential Exhibit A.].

The definition of the cost of equity capital for a firm is investors' expected long-term return. The Company's long-term expected return on the portfolio of common stocks in its pension fund represents the cost of equity capital on the stock market, in general. That long-term equity return expectation for the common stocks in the Company's own pension fund is below the equity return I recommend in this proceeding for an electric utility operation with substantially lower operating risk. Therefore, the Company's own investment return projections published in its S.E.C. filings, provide compelling evidence that, 1) my 9.25% recommendation is reasonable if not conservative and 2) Dr. Avera's 11.50% recommendation is substantially inflated.

Q. ISN'T IT POSSIBLE THAT THE EQUITY RETURN PROJECTIONS FOR THE COMPANY'S PENSION FUND ARE LOW IN ORDER NOT TO EXAGGERATE THE FUTURE VALUE OF THAT FUND?

A. It is reasonable to believe that the Company would not want to use return expectations that are too high for its pension fund assets because that would exaggerate the expected future value of that fund. Moreover, if the assumed returns are continually over-estimated, the Company would be left with unfunded pension liabilities that could add unnecessarily to the Company's financial risk profile.

However, it is also reasonable to believe that the Company would not want to underestimate the pension fund return estimates, because that would call for an unnecessarily high annual contribution every year to reach the future targeted amount of pension funds. An unnecessarily large pension expense would reduce the Company's bottom line. In addition, if ultimate returns turn out to be higher than predicted, the Company will, effectively, have pre-funded its pension requirements, using funds that could have been put to other, more economically beneficial uses such as production or transmission facilities.

Therefore, because there are negatives associated with either over- or under-stating expected pension portfolio returns, we must assume the Company and its pension fund managers accurately estimate their expected investment returns and actually believe that, over the long-term, the common equity return expectations for its pension fund investments are in the single-digit range, cited above.

Q. EXPECTED EQUITY RETURNS IN THE SINGLE-DIGIT RANGE SEEM TO BE LOW. ARE THERE OTHER EXAMPLES OF INVESTOR-EXPECTED EQUITY RETURNS SIMILAR TO THOSE USED IN THE COMPANY'S PENSION FUND PLANNING?

A. Yes, there are examples in the capital marketplace and the financial media indicating that investor return requirements are quite modest. For example, a recent A.G. Edwards report on the gas utility industry, shows that market return expectations for gas utility stocks are well below 10%.[3] The report states that, for a sample of 16 large and small gas distributors, the median total return expectation (dividend yield plus expected growth—a DCF-type calculation) is 8.1%.

Value Line publishes similar expected low returns for the electric utilities used in my similar-risk sample group to estimate the cost of equity for APS. As part of the data array published for each of the companies it follows, Value Line publishes its expectations for a three- to five-year total return (dividends plus stock price change). For the electric utilities that I use to estimate the cost of equity in this proceeding, Value Line currently projects a three- to five-year total return expectation ranging from 2.0% to 9.38%. In other words the *upper end* of the expected total return spectrum for the electric utility companies in my sample group is similar to my equity return recommendation in this proceeding. The return expectations for energy utilities published by AG Edwards and Value Line are representative of the equity return expectations presented to investors today and are generally below my recommended return on common equity in this proceeding.

In addition, in a letter published in late 2004 by Public Utilities Fortnightly, a prominent electric industry analyst confirms that single-digit return expectations are

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[3] A.G. Edwards, "Gas Utilities Quarterly Review," April 6, 2006.

reasonable for utility investments, and those expectations comport with recent economic research:

> "Finally, let's get real about investor expectations, now that investors have begun to get real. Articles on the topic fill the financial journals. They feature variants on this theme: Over time the average equity investment produces an annual total return (dividends plus stock price appreciation) of 6.5 per cent per year in real terms, the bulk of which comes from the dividend component. Add inflation expectations to that number, and you get an 8.5 to 9.5 percent return in nominal terms. The average back-to-basics utility yields about 5 to 6 percent and might grow 3 to 4 percent per year, which adds up to produce a total return expectation of 8 to 10 percent per year, not far from the return the journals posit for the market." (Hyman, Leonard, Senior Consultant, R.J. Rudden Associates, "Letters to the Editor, *Public Utilities Fortnightly*, August 2004, p. 10)

The "articles in the financial journals," to which the author of the preceding quote refers, relate to recent research involving the market risk premium. The market risk premium is the additional return above the risk-free rate of interest that investors expect to earn by investing in stocks rather than risk-free U.S. Treasury securities. This recent research indicates that the market risk premium based on the often-cited Ibbotson historical data substantially overstates investor expectations for returns in the future.

Finally, the expectation of lower equity returns and lower risk premiums is not confined to academic journals. It has been published in the popular financial media. As the excerpt from a 2003 article in *Fortune* cited below notes, double-digit returns on the stock market are not a reasonable expectation for investors today.

> "For the real story, we turned to some top quantitative scholars. This cabal of quants [quantitative analysts] follows the market's most fundamental math, and it's telling them that investors should downsize their expectations. Yes, some individual stocks will return 10% or better. And yes, even we at FORTUNE think we can identify a few of the winners—as you'll see in the stories throughout this special issue. But the best the market *as a whole* can pull off is 6% to 8% annual returns....

> [Cliff] Asness is not the only scholar urging caution. He's joined by such heavyweights as Kenneth French of Dartmouth, who wrote some of the most important stock market studies of the past two decades with Eugene Fama of the University of Chicago. Also in this pack is Jeremy Siegel of Wharton, whose book, *Stocks for the Long Run*, helped mold academic thinking on how equities perform over long periods. They have all come to the same cautious predictions about the markets because a crucial number in investing—their Holy Grail— is pointing toward lower returns. That number is the 'equity risk premium.' Since the mid-1980s the risk premium has been one of the key concepts in academic work on the stock market. 'It's the core number,' says French. 'If anything exercises a gravitational pull on stocks, it's the risk premium.'" (Greif, G., "Can Stocks Defy Gravity?"*Fortune*, June 16, 2003, pp. 44-50.)

Q. PLEASE EXPLAIN HOW THE CURRENT RESEARCH RELATED TO THE MARKET RISK PREMIUM SUPPORTS YOUR ESTIMATE OF THE COST OF EQUITY CAPITAL.

A. As noted above, the market risk premium is the difference between the return investors expect on stocks and the return they expect on bonds (often a risk-free rate of return like a U.S. Treasury bond). The "traditional" view, supported primarily by the earned return data over the past 80 years published by Ibbotson Associates[4], is based on the historical difference between the returns on stocks and the returns on bonds. That view assumes that the returns actually earned by investors over a long period of time are representative of the returns they expect to earn in the future.

For example, the Ibbotson data show that investors have earned a return of 12.3% on stocks and 5.8% on long-term Treasury bonds since 1926.[5] Therefore, based on those historical data, it is often assumed that investors require a risk premium in the future of 6.5% above the long-term risk-free rate to invest in stocks [12.3% - 5.8% = 6.5%]. With a current long-term T-Bond yield of 5.2%, that assumption indicates an investor expectation

[4] Ibbotson Associates is a investor service firm that publishes historical data related to the stock and bond markets from 1926 through the most recent year. The publications are updated each year.

[5] Ibbotson Associates, SBBI Valuation Edition, 2006 Yearbook, p. 28.

of an 11.7% return for the stock market in general [5.2% + 6.5% = 11.7%]. Of course, expected utility returns would be considerably lower, because utilities have less investment risk than the stock market, generally.

However, in addition to the fact that past experience (even long term experience) may not necessarily be representative of current expectations for future returns, there are aspects of the Ibbotson data that, when examined, point not only to lower historical risk premiums than those reported by Ibbotson but also expected risk premiums that are much lower.

One recent article that evaluates returns over the past 100 years in the U.S. as well as other established stock markets, "Risk and Return in the 20th and 21st Centuries," is authored by Dimson, March and Staunton. Those researchers summarize their findings this way:

> "The single most important contemporary issue in finance is the equity risk premium. This drives future equity returns, and is the key determinant of the cost of capital. The risk premium—the expected reward for bearing the risk of investing in equities, rather than in low-risk investments such as bills or bonds—is usually estimated from historical data....The authors show that the historical equity risk premium has been lower than previously believed, and argue that the future risk premium is likely to be lower still." (Dimson, March, Staunton, "Risk and Return in the 20th and 21st Centuries," *Business Strategy Review*, 2000, Volume 11, Issue 2, pp. 1-18)

Dimson, et al, show that the Ibbotson historical data set, which measures return data from 1926 forward, suffers from survivor bias. Simply put, Ibbotson's data is based on the stock market results of only the successful stocks, i.e., those that were successful enough to be listed on a major U.S. exchange. The return data of the stocks that did not grow large enough to be listed on a stock exchange or data from markets or time periods that were difficult to measure are not included in the Ibbotson data—and Ibbotson's results are overstated for that reason. Dimson, et al, measure historical returns over a longer period than

Ibbotson—100 years of data—and includes an analysis of the returns of stock markets in other countries, which gives a broader sample of investor opinion than Ibbotson's data, which is limited to the US equity markets.

Researching more data over a longer period of time, those authors come to the conclusion that over the past 100 years common stocks have earned an average arithmetic return that is 5.0% above Treasury bonds.[6] Ibbotson's return difference between stock and long-term bonds is 6.5%. However, Dimson argues that historical results, alone, are not accurate measures of future returns expectations unless the abnormalities in the historical record that are unlikely to exist in the future are removed in order to project for the future. Taking those facts into account, the authors conclude that, "the key qualitative point is that [the expected risk premium] is lower than the raw historical risk premium."

There is other research on historical returns that uses even longer time periods that the 100-year span used by Dimson. In Stocks for the Long Run, A Guide to Selecting Markets for Long-term Growth (Irwin Professional Publishing, Chicago, IL, 1994, pp. 11-15), Professor Jeremy Siegel concludes that between 1802 and 1992, the return differential between stocks and long-term Treasuries ranged from 3.4% to 5.1%. Using the approximate mid-point, a 4% historical risk premium would indicate that investors could reasonably expect a stock market return of about 9.2% (5.2% long-term T-Bonds plus a 4% risk premium). Of course, if future risk premium expectations are lower than what has existed historically, even that 9.2% estimate would be too high.

Therefore, recent academic research on the historical market risk premium, using longer time periods and a broader range of stock market data than the reported Ibbotson risk premiums, show that those data overstate long-term historical market risk premiums. Moreover, that other research indicates that the risk premium investors expect for the future—the prime determinant of today's equity return requirements—is lower than long-term historical experience would indicate.

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[6] A market risk premium of 5% added to a current T-Bond yield of 5.2% would indicate an equity return expectation for common stocks of 10.2% (expected utility stock returns would be lower).

Q. IS THERE ADDITIONAL RECENT RESEARCH REGARDING THE MARKET RISK PREMIUM THAT IS NOT BASED PURELY ON HISTORICAL EARNED RETURNS, AND WHICH SHOWS THE RISK PREMIUM TO BE SUBSTANTIALLY LOWER THAN THAT PUBLISHED BY IBBOTSON?

A. Yes, there is new research regarding the risk premium, which is not based on historical earned returns. That research indicates the Ibbotson data is skewed upward and that the forward-looking market risk premium is much lower. In 2003, widely respected researchers Eugene Fama and Kenneth French published an article in *The Journal of Finance* focusing on the equity risk premium and measured (instead of the realized return) the expected return on the market less the expected return on bonds (the yield) over a long-term period as well as several sub-periods. Their research based on long-term historical expected returns indicates that the *expected* (i.e., forward-looking) risk premium is in the range of 2.6% to 4.3%.[7]

More recently, Graham and Harvey (Duke University), in conjunction with *CFO Magazine* have begun to regularly poll corporate financial officers regarding their expectations regarding the expected market risk premium. The most recent result of the quarterly poll (January 2006) indicates that the financial executives polled expect stock returns over the next ten years to be only 2.4% higher than bond returns. Since the survey was initiated (2000), the forward-looking market risk premium has ranged from about 2.5% to 4.5%. That means that corporate financial officers—individuals that are arguably well versed in capital markets—expect equity returns to range from 2.5% to 4.5% above ten-year US Treasury bonds. With current Treasury bond yields of approximately 5.2%, the Duke survey pegs investor equity return expectations ranging from 7.7% to 9.7%. In comparison to that expected range of returns for the stock market in general, my 9.25% equity return recommendation for APS's electric utility operations can only be characterized as generous.

Another survey approach to determining the market risk premium, was recently published by Professor Ivo Welch in the *Journal of Business*. The survey polled more that

[7] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2003, pp. 637-659.

500 finance and economic professors regarding their expectations about the long-term market risk premium and stock market return. That survey indicated that the median risk premium expectation was 5%, and the median geometric long-term stock market return expectation was 9% (implying an arithmetic stock market return expectation of about 10%). Again, a 10% expected return for the stock market generally would imply lower returns for utility operations.

Finally, even Roger Ibbotson, whose firm (Ibbotson Associates) is the largest purveyor of historical market return data, recently published a paper responding to some of the recent research suggesting lower forward-looking market risk premiums, which confirms that risk premium expectations for the future are below what they were in the past.[8] Ibbotson's projected risk premium of 3.97% to 5.90%, is about 1.25% lower than his own pure historical return averages indicate; and the long-term return for the stock market he projects using those risk premiums is 9.37%. Even though Ibbotson's projected return for the stock market is similar to my equity return estimate for APS in this case, it is important to understand that a) his forward-looking estimate is for the stock market as a whole, not for lower-risk utilities and b) his estimate is at the upper end of the spectrum produced by the current research on the market risk premium.

I have mentioned only a few of the research articles regarding the market risk premium that have been published over the last few years. There have been many and the vast majority of them indicate that the expected market risk premium is below that exhibited in the Ibbotson historical data. That information, as well as the research cited above, indicate that my 9.25% equity return recommendation for the utility operations of APS in this proceeding is certainly reasonable and, if the new research regarding risk premiums is correct, may be too high.

[8] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

Q. IF THE CURRENT EQUITY RETURN INVESTORS ACTUALLY EXPECT IS WELL BELOW 10%, HOW DO YOU EXPLAIN THE FACT THAT REGULATORS, ON AVERAGE, HAVE BEEN ALLOWING UTILITIES TO EARN EQUITY RETURNS OF ABOUT 10.5%?

A. While this Commission has recently allowed equity returns that are within a reasonable range for utilities (i.e., below 10%), I believe that regulatory commissioners, in general, are not aware of the significant new research regarding the market risk premium and the reduction of long-term investor return expectations. As that information becomes more widely known and understood, I would expect allowed returns to decline. In addition, DCF cost of equity estimates have tracked actual capital costs quite well (DCF results have been below 10% for some time now), however other evidence considered by regulators is based primarily on historical risk premium information, which, as noted above, substantially overstates current investor expectations. In that way, I believe those equity return awards are based on inaccurate risk premium information that tends to overstate the cost of capital.

Clearly, recent academic research supports and investment advisors project that over the long-term, expected equity returns are below 10%. I believe that regulators will eventually follow their lead.

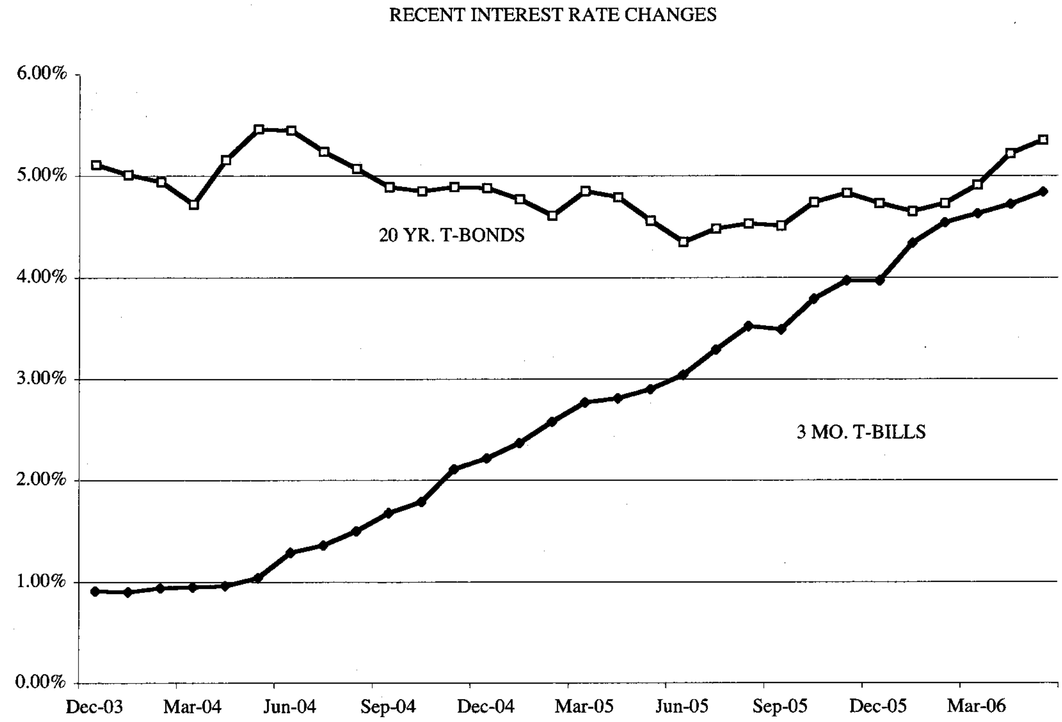
II. ECONOMIC ENVIRONMENT

Q. WHY IS IT IMPORTANT TO REVIEW THE ECONOMIC ENVIRONMENT IN WHICH AN EQUITY COST ESTIMATE IS MADE?

A. The cost of equity capital is an expectational, or *ex ante*, concept. In seeking to estimate the cost of equity capital of a firm, it is necessary to gauge investor expectations with regard to the relative risk and return of that firm, as well as that for the particular risk-class of investments in which that firm resides. Because this exercise is, necessarily, based on understanding and accurately assessing investor expectations, a review of the larger economic environment within which the investor makes his or her decision is most important. Investor expectations regarding the strength of the U.S. economy, the direction of interest rates and the level of inflation (factors that are determinative of capital costs) are key building blocks in the investment decision. Those factors should be reviewed by the analyst and the regulatory body in order to assess accurately investors' required return—the cost of equity capital to the regulated firm.

Q. DOES THE OBJECTIVE EVIDENCE AVAILABLE IN THE CURRENT ECONOMIC ENVIRONMENT INDICATE THAT CAPITAL COSTS CONTINUE TO BE LOW?

A. Yes. First, the overall level of fixed-income capital costs has been relatively low for several years, and continues to be relatively low at the current time. Although, as shown in the chart below, there has been steady upward movement in *short-term* interest rate levels over the past two years as the Federal Reserve (the Fed) has raised the Federal Funds rate, long-term interest rates have fluctuated in a range of 4.5% to 5.5% over the past two years. This indicates that even though the Fed has raised short-term interest rates and the spread between long-term and short-term treasuries is well below the historical average, investors are not convinced that the overall level of economic growth will be sufficient to warrant an increase in long-term interest rates and long-term capital cost rates. As a result long-term capital costs have not increased to a substantial extent, even though the Federal Reserve has drastically increased short-term rates.



Data from Federal Reserve Statistical Release H.15

Another indication of the reason investors are willing to buy and hold stocks that offer what seem to be relatively low returns is shown in Exhibit__(SGH-1), Schedule 1, page 1, which depicts Moody's Baa-rated bond yields from 1984 through April 2006. Page 1 of Schedule 1 shows that interest rates over the past couple of years are very low relative to the interest rate levels that existed in the mid-1980s, and are part of a general downward trend in capital costs begun in 2000.

Also, page 2 of Schedule 1 (Exhibit__(SGH-1)), which presents the year-average Moody's Baa-rated bond yields for each year over the past 37 years (1968-2006), shows that Baa-rated bond yields thus far in 2006, even with a slight increase from 2005 levels, are below the bond yield levels seen in the U.S. in the late 1960s. Also, the most recent average Baa-rated utility bond yield, 6.6%[9], falls at the lower end of the range of interest rates that

[9] Value Line *Selection & Opinion*, most recent six weekly editions (5/26/06-6/30/06, inclusive), 20/30-year Baa-rated utility bond yield averages.

have existed over the past 30 years (See Schedule 1, page 2). Simply put, a fundamental reason that the current cost of common equity capital for electric utility operations of 9.25% to 9.75% is reasonable is that long-term capital cost rates are as low as they have been in more than thirty years.

The above data indicate that capital costs, even with the recent credit tightening by the Federal Reserve Bank (the Fed), remain at low levels and generally support the reasonableness of relatively low equity capital costs.

Q. WHAT IS THE CURRENT EXPECTATION WITH REGARD TO THE ECONOMY AND INTEREST RATES?

A. As Value Line notes in its most recent Quarterly Review the current expectation is that the economy will expand at a more moderate pace during 2007, and inflation and interest rates will continue to be relatively moderate. The following excerpts from Value Line explain how a relatively low interest rate environment will be preserved:

> **Inflation**: We aren't assuming that inflation will suddenly surge. However, we do sense that record oil prices, the relentless rise in industrial materials prices, and the recent rise in wage costs will combine to produce somewhat higher inflation. Helping to limit these likely pricing pressures should be moderating GDP [Gross Domestic Product] growth, stabilizing energy prices, and additional increases in productivity. Nevertheless, with the outlook for growth brightening in parts of Europe and Asia, it is unlikely we will see a sustained drop in the prices of oil, precious metals, or commodities. However, we may still see a selective easing in producer and consumer prices later this year. [Chart omitted].
>
> **Interest Rates**: On May 10th, the Federal Reserve raised the Federal Funds rate from 4.75% to 5.00%, the 16th consecutive increase in that key short-term lending rate. The Fed also indicated that future rate action would be contingent on the strength of the economic data going forward. Given the likely moderation in GDP growth in the second half of this year, we think the Fed will call a halt to its rate tightening initiatives over the summer, with one or two additional rate hikes at most. Such a course should not bring the business expansion to a premature end. As noted, we think the Fed's subsequent moves—which may take place as early as next spring—will focus on reducing rates in recognition of a

> probably slowing in GDP growth and a likely stabilization of inflation.[Chart omitted]. (The Value Line Investment Survey, *Selection & Opinion*, May 26, 2006, pp. 1258-60.)

In that most recent Quarterly Economic Review, cited above, Value Line projects long-term Treasury bond rates will average 5.3% through 2007 and 5.5% through 2008. The recent six-week average 30-year T-bond yield is 5.16% (data from Value Line, *Selection & Opinion*, six weekly editions, May 26, 2006, through June 30, 2006). Therefore, the indicated expectation with regard to interest rates is that they are likely to move slightly higher, but remain within a range near current levels.

Q. IS IT REASONABLE TO CONLUDE THAT INVESTORS ARE AWARE OF THE EXPECTATIONS FOR SOMEWHAT HIGHER INTEREST RATES IN THE FUTURE, AND HAVE REACTED TO THAT NEWS?

A. Yes. A widely accepted tenet of modern finance is that U.S. capital markets are efficient in quickly assimilating into stock prices news that impacts stock valuation. Higher interest rates have been forecast for some time and, it is reasonable to believe, utility investors have incorporated that expectation into the stock prices they are willing to provide for utility stocks. Therefore, when estimating the cost of equity capital it is necessary to consider current interest rate levels, not projected levels, because current interest rates best represent investors' current expectations for the future. Just as it is standard procedure to use current market prices rather than prices projected sometime in the future in order to determine DCF-type equity cost estimates, the use of current bond yields rather than projected yields provides the best indication of investors' return expectations.

Q. DOES THE CURRENT LEVEL OF MARKET-TO-BOOK RATIOS EXISTING IN THE ELECTRIC INDUSTRY, ALONG WITH INVESTORS' EXPECTATIONS REGARDING THE RETURN ON BOOK EQUITY THAT ELECTRIC UTILITIES ARE EXPECTED TO EARN, SUPPORT YOUR 9.25% EQUITY COST ESTIMATE?

A. Yes. It is a long-held and widely-understood tenet of regulatory finance that when investors are providing market prices above the book value of utility stocks, the return investors expect (the cost of capital) is below the return the utility will earn on that book value. In other words, when market prices are above book value, investors expect utilities to earn accounting returns (ROEs, returns on book value) that are greater than the market-based cost of equity capital for those companies.

In the current market environment, the market price of electric utility stocks used in my testimony to estimate the cost of equity is 69% higher than their book value (i.e., M/B = 1.69).[10] Moreover, Value Line reports that those electric utilities are expected to earn returns on the book value of their equity capital over the next three to five years of 10.35%[11]. Those data indicate that it is unreasonable to believe the cost of equity capital for electric utilities is even near, much less above 11% (e.g. 11.50%, as Dr. Avera indicates), and that the lower cost of equity that I recommend is more representative of investor expectations.

Q. WHAT IS THE DIFFERENCE BETWEEN THE EXPECTED RETURN AND THE COST OF CAPITAL?

A. The expected return is the return on book equity (ROE) that the utility is expected to earn. That return is an accounting return. It is based, in part, on the return allowed by the regulator, the company's operating efficiency and on other income available to the firm (if the firm has unregulated operations). The cost of equity capital is the return investors require to commit equity capital to a particular enterprise. That is the cost of equity capital to the firm—the minimum return investors require in order to invest in a particular type of company. That return is a market-based return, because whatever return the investor receives (yield + dividend growth) will be measured against the market price the investor provided to purchase the stock.

Regulators seek to set the allowed return equal to the cost of equity capital for the

[10] See Exhibit__(SGH-1), Schedule 5, p. 1.
[11] See Exhibit__(SGH-1), Schedule 10, p. 1.

same reason they set the return allowed on utility debt equal to the cost of that type of capital. Utility rates should be cost-based. That includes the cost of money—equity and debt. Investors understand that utility returns are allowed and earned on the book value (original cost less depreciation) of the utility's plant investment. That long-standing regulatory paradigm has been in existence for many, many years and, through informationally efficient markets, utility investors are aware of that fact.

Q. PLEASE EXPLAIN IN MORE DETAIL WHY A UTILITY'S MARKET-TO-BOOK RATIO IS INDICATIVE OF THE RELATIONSHIP BETWEEN THE EXPECTED RETURN AND THE COST OF EQUITY CAPITAL.

A. A simple example will illustrate this important point. Assume that a utility has a book value of equity capital equal to $10 per share. Let's also assume, for simplicity of exposition, this utility pays out all its earnings in dividends. If regulators allow the utility a 12% return on that equity, investors will expect the company to earn (and pay out) $1.20 per share. If investors require a 12% return on this investment, they will be willing to provide a market price of $10 per share for this stock ($1.20 dividends/$10 market price = 12% required return). In that case, the allowed/expected return (12%) is equal to the cost of capital (investors' required return, 12%), and the per-share market price is equal to the book value (M=B, or M/B=1.0).

To conform our example to the market situation that presently exists with electric utilities, let's assume that investors' required return (the utility's cost of equity capital) falls to 10%, but the utility continues to be allowed a 12% return on the equity portion of its rate base investment. Investors would be drawn to a utility stock in a risk class for which they require a 10% return but which was expected to pay out a 12% return. This increased demand by investors would result in an increase in the market price of the stock until the total share yield equaled the investors' required return. In our example, that point would be $12 per share ($1.20 dividends/$12 market price = 10% required return). In that case, the allowed/expected return (12%) is greater than the required return (10% - the cost of equity capital) *and* the per-share market price ($12/share) exceeds the book value ($10/share), producing a market-to-book ratio greater than one ($12/$10 = 1.20).

Therefore, the market-to-book/expected return relationship that actually exists today in the market for utility stocks indicates that investors expect that those companies will earn a return on the book value of their equity (ROE) which exceeds the cost of equity capital.

Q. HOW CAN ELECTRIC UTILITIES HAVE PROJECTED BOOK EQUITY RETURN OF 10.35% AND A COST OF EQUITY OF 9.25%?

A. If investors were providing stock prices (market prices) that approximated the book value of electric utilities, that is if M/B ≈ 1.0, and those companies were expected to earn a 10.35% return on book value, then it would be reasonable to believe that the cost of capital (investors' market-required return) would approximate 10.35%. However, if investors are willing to provide a stock price that is considerably <u>more</u> than book value for a group of stocks that is expected to earn an 10.35% return on book value, their expected return on that stock price (the cost of equity capital to the firm) must be <u>less</u> than the expected return on book value—i.e., less than 10.35%. Currently, investors are paying about 169% of book value for their electric utility investments. Therefore, they must require a return below the 10.35% expected to be earned on book value. In that regard, the range cost of equity estimates I provide in this proceeding (between 9.25% and 9.75%) is reasonable.

Finally, the market price/book value data cited above provides dramatic evidence that Dr. Avera's equity return estimate of 11.50% cannot represent investor's expectations. If an investor required an 11.50% return on a stock that she expected to earn 10.35% on book value, would she pay <u>more</u> than book value for that stock? Clearly, the answer is no. Therefore, Dr. Avera's cost of equity estimate cannot be accurate.

Q. IS THE RELATIONSHIP BETWEEN A UTILITY'S MARKET-TO-BOOK RATIO, THE EXPECTED BOOK RETURN, AND THE COST OF EQUITY CAPITAL YOU HAVE JUST OUTLINED WELL DOCUMENTED IN THE REGULATORY FINANCIAL LITERATURE?

A. Yes. The DCF model is often referred to as the "Gordon model" because of the definitive work Professor Myron Gordon has done regarding the DCF model and the cost of equity capital of utilities. Professor Gordon understood that market prices are not necessarily equal to book value and the DCF is not predicated on that concept. Further, he has shown that the market-to-book value ratio is greater than (equal to, less than) one when the ratio of the allowed (or expected) rate of return to the cost of capital is greater than (equal to, less than) one. Gordon, M.J., The Cost of Capital to a Public Utility, 63-64 (1974). There is also additional support in the financial literature for the value of market-to-book ratios in regulation.[12]

It is important to realize that the relationship between market price and book value for a utility operation is not a linear or one-for-one relationship. That is, just because the stock price of a particular utility is, say, 50% above its book value does not indicate that its cost of equity is 50% below the utility's expected book return. Also, there are differences between book value and rate base, which means that, even if a utility is allowed and expected to earn its cost of equity capital, the market price may not exactly equal book value. For utility operations, it will approximate book value, however, as supported in the financial literature noted above. Nevertheless, while market-to-book ratios do not provide a definitive answer with regard to a utility's cost of equity capital, when they are reviewed in conjunction with expected returns on book equity, market-to-book ratios provide valuable information regarding the proper range of equity capital costs for utilities.

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[12] Kolbe, Read, Hall, The Cost of Capital, Estimating the Rate of Return for Public Utilities, 25-33 (1986); Lawrence Booth, ("The Importance of Market-to-Book Ratios in Regulation," NRRI Quarterly Bulletin, Vol. 18, No. 4, at 415-16 (Winter 1997)

Q. MR. HILL, ARE YOU INDICATING THAT UTILITY STOCK PRICES SHOULD EQUAL BOOK VALUE?

A. No. Regulation is not designed to be a stock price setting mechanism, and regulators should not target any particular stock price in the ratesetting process. Investors set the market price, depending on the risk/return matrix presented to them in the current and expected market environment. However, the relationship among utility market price, book value, expected ROE and the cost of capital is well known and offers valuable information regarding the reasonableness of a cost of equity estimate. Without making any determination of what electric utility stock prices ought to be, we can observe these facts: utility market prices are about 65% higher than book value. Utilities are projected to earn a return on book value of 10.5%. Because utility investors are paying substantially <u>more</u> than book value for a share of utility stock, their required market return (the cost of equity capital to the utility) must be well below that expected return on book value.

III. CAPITAL STRUCTURE

Q. WITH WHAT CAPITAL STRUCTURE DOES THE COMPANY REQUEST RATES BE SET IN THIS PROCEEDING?

A. Schedule D-1 of the Company's filing presents its requested ratemaking capital structure. The Company has filed its rate request based a capital structure consisting of 45.50% long-term debt, and 54.50% common equity.

Q. IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE SIMILAR TO THE MANNER IN WHICH IT HAS BEEN CAPITALIZED RECENTLY?

A. No. According to the Company's 2004 S.E.C. Form 10-K, Arizona Public Service Company was capitalized at year-end 2003 and 2004 with an average capital structure that consisted of approximately 45% common equity and 55% long-term debt.[13] More recently, as shown on page 1 of my Schedule 2, and according to data presented by the Company to the financial community in its S.E.C. filings, over the most recent five quarters, APS began the period with a capital structure that was similar to that which had existed on average over the previous two years. In March 2005, APS was capitalized with about 46.5% common equity and 53.5% long-term debt.

In September 2005 the Company's common equity ratio jumped dramatically to approximately 54% of total capital. Over the past five quarters, as shown on page 1 of Schedule 2 attached to my testimony, APS was capitalized with approximately 51.5% common equity, and 48.5% long-term debt.[14]

Therefore, the manner in which the Company has been capitalized historically is very different from the capital structure requested by the Company in this proceeding. In addition, because the Company witnesses make cautionary statements regarding the Company's financial risk and its bond rating, it is important to understand that during the time that APS was capitalized with a 45% common equity ratio, it maintained investment-grade bond ratings.[15] In other words, the Company has maintained an investment-grade bond rating with a 45% common equity ratio and, now, requests that rates be set using a much more expensive capital structure containing about 55% common equity.

Q. WHAT ARE THE IMPLICATIONS OF THE CAPITAL STRUCTURE CHANGES YOU HAVE DESCRIBED?

A. For the past couple of years, APS has maintained an investment grade bond rating with a capital structure consisting of 45% common equity as a percentage of total capital. Then, prior to the filing of this rate case, the parent company infused equity into its regulated

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[13] Pinnacle West 2004 S.E.C. Form 10-K, p. 131. December 31, 2003 capital structure: 45.66% common equity, 54.34% long-term debt. December 31, 2004 capital structure: 45.09% common equity and 54.91% long-term debt.

[14] See Exhibit__(SGH-1), Schedule 2, page 1, based on data from Company response to RUCO-3-1, p. 1.

[15] S.E.C. Form 10-K, 2003, 2004, 2005.

subsidiary so that the common equity ratio of the latter is approximately 54% of total capital— about 10% percentage points higher.

In addition, the Company indicates that after this rate case, its current common equity ratio will not be sustained. In its Filing Schedule D-1, APS indicates that by year-end 2007, its common equity ratio will decline by almost three percentage points from the currently requested level. Those data indicate that following the rate case, the Company's common equity ratio will trend downward from its currently elevated levels.

Also, the Company indicates in its presentations to bond rating agencies that the common equity ratio of its riskier parent Company, Pinnacle West, will also decline from current levels to [redacted] of total capital.[16] Therefore, the data presented by the Company indicates that subsequent to the very high common equity ratios immediately following the recent issuance of common equity, the common equity ratios of both APS and PNW are expected to decline.

Q. WHAT SORT OF ANNUAL COST INCREASE IS IMPLIED BY THE COMPANY'S CAPITAL STRUCTURE SHIFT?

A. Based on data provided by the Company, the capital structure shift from 45% common equity to the requested 54.5% common equity, if adopted in ratemaking by this Commission, would add approximately $58 Million to the electric rates of APS' Arizona customers every year. Page 2 of Schedule 2 shows the Company's requested capital structure and cost rates at the top of the page. Assuming a combined State and Federal tax rate of 40%, the Company's requested capital structure implies a pre-tax overall cost of capital of 12.91%. Using a capital structure that APS actually used in 2003 and 2004 and using the Company's requested capital cost rates, the pre-tax overall return would be 11.60%. The difference in overall return (1.31%) multiplied by the Company-requested rate base ($4.467 Billion), indicates that the capital structure shift made prior to the filing of this

[16] Provided in response to RUCO-3-6, APS10113, p. 76 of 80 [Data redacted. Confidential data provided in Exhibit A]

rate proceeding, if approved by this Commission, would cost Arizona ratepayers $58.4 Million annually.

Q. HOW IS APS's PARENT COMPANY, PINNACLE WEST, CAPITALIZED?

A. Page 3 of Schedule 2 shows the capital structure of APS's parent company, Pinnacle West, Inc., over the past five quarters. The parent company's common equity ratio began the period at about 48% of total capital, rose to 53% of total capital by year-end 2005 and, by March 2006, had declined to 50% of total capital. The parent's capital structure over that most recent five-quarter time period averaged 50.20% common equity, 49.06% long-term debt and 0.74% short-term debt.

Q. THE PARENT COMPANY HAS MORE DEBT AND LESS EQUITY THAN THE RATEMAKING CAPITAL STRUCTURE REQUESTED BY APS. DOES THE PARENT COMPANY ALSO HAVE LOWER OPERATIONAL RISK THAN UTILITY OPERATIONS?

A. No. Pinnacle West (PNW) is an energy services holding company that contains several business platforms. The majority of those operations (75% of 2005 revenues) are the regulated electric utility operations of APS, which have relatively low operational risk and are the primary influence on Pinnacle West's business risk. However, Pinnacle West also owns two other operating segments: a real estate segment (11% of 2005 revenues), and an energy trading segment (12% of 2005 operating revenues). The energy trading segment consists of competitive energy business activities, including wholesale marketing and trading and APS Energy Services (commodity-related energy services). As a result, on a consolidated basis, Pinnacle West has greater operating (business) risk than APS.

Q. WHAT DOES THE RELATIVE BUSINESS RISK OF A FIRM HAVE TO DO WITH ITS CAPITAL STRUCTURE?

A. The manner in which a firm is most economically capitalized is a function of the volatility of the income stream generated by the assets of the firm or, in other words, the firm's operating (business) risk. For example, if a firm has an income stream that is not volatile and which can be predicted with near certainty, then a capital structure consisting of even 100% debt would not be problematic or risky. In fact, it would be the most cost-effective capital structure in that instance because debt is the least expensive form of investor-supplied capital for a firm and, without the possibility of operating income being insufficient to meet the debt service requirements, a 100% debt capital structure would be the prudent choice.

As the income stream of a firm becomes more volatile (more risky), financial theory holds that the amount of debt used should decline in order to avoid a default event (the failure to meet the required debt service costs). Although the reduction of lower-cost debt and the addition of higher-cost common equity will raise the firm's overall cost of capital, that increase is appropriate and economically efficient because it more appropriately matches the firm's financial risk with the increase in business risk. In that way, given an increased level of business risk, the cost of capital is minimized and the financial health of the firm is better assured.

An example of how the amount of debt in the capital structure varies with the operational or business risk of a firm is found in a recent publication by Standard & Poor's regarding utility business risk. A June 2004 publication by Standard & Poor's, in which that bond rating agency re-aligned its business risk profile scores for utility companies, indicates that the companies with higher business risk are required to have a lower debt ratio (less debt, more equity) in order to earn the same bond rating as a firm with lower business risk.[17]

[17] See Company Filing, Attachment III-F-4-C, Standard & Poor's Ratings Direct, New Business Profile Scores Assigned for U.S. Utility and Power Companies: Financial Guidelines Revised, June 2, 2004.

For example, Standard & Poor's indicates that energy merchant/marketing companies have high business risk. On a scale of 1 to 10 with, 10 representing the highest risk, energy trading companies have an average business risk profile score of 9. In order to achieve a bond rating of "BBB", companies with a business risk profile of 9, according to Standard & Poor's, should have a total debt ratio ranging between 40% and 50% of total capital. (A debt ratio between 40% and 50% corresponds to an equity ratio between 50% and 60%.)

In contrast, integrated utilities, like APS, have lower business risk than energy trading companies. S&P currently assigns APS a business risk profile score of 6. According to Standard & Poor's, in order to achieve a "BBB" bond rating, companies with a business profile score of "6"should be capitalized with a total debt ratio between 48% and 58% of total capital (or an equity ratio between 42% and 52% of total capital). Therefore, companies with lower business risk (like fully-integrated electric utility operations) are effectively capitalized with more debt and less equity than companies with higher business risk (like energy marketing companies).

Q. WHY IS IT OF CONCERN TO THIS COMMISISON THAT PINNACLE WEST HAS HIGHER BUSINESS RISK THAN APS, BUT A MORE HIGHLY LEVERAGED CAPITAL STRUCTURE THAN THAT REQUESTED BY THE COMPANY FOR RATESETTING PURPOSES?

A. There are two reasons. First, as I noted above, firms that have higher business risk should be capitalized more conservatively, i.e., with more equity and less debt than firms that have lower business risk. However, in this instance Pinnacle West is capitalizing its consolidated operations with a common equity ratio substantially lower than that requested for ratemaking purposes by its utility subsidiary, APS. Rating agencies recognize that unregulated operations carry greater risk than regulated operations.

> In general, regulated utilities offer lenders some of the lowest business risks seen amongst corporate entities. However, many of the companies in question may also be active in unregulated businesses, such as speculative trading with exposure to unhedged commodity prices, which can be highly risky and may lead to serious financial difficulties despite the presence of a regulator.
>
> Moody's framework for rating regulated electric utilities is constructed around a number of credit risk factors rather than on any on particular metric such as a financial ratio.
>
> The *first step* is to assess the extent of a "regulated" company's exposure to unregulated businesses. The strongest position is enjoyed by those companies operating in a wholly regulated business. (Moody's Investors Service, Global Credit Research, Rating Methodology: Global Regulated Electric Utilities, March 2005, pp. 1, 4, emphasis added)

Second, a more highly leveraged capital structure at the parent company level, when the regulated subsidiary faces lower business risk, constitutes financial cross-subsidization of the unregulated parent (PNW) by the ratepayers of the regulated entity (APS).

Q. PLEASE EXPLAIN WHAT YOU MEAN BY FINANCIAL CROSS-SUBSIDIZATION AND WHY THIS COMMISSION SHOULD BE CONCERNED.

A. Cross-subsidization of a parent company's unregulated operations by its regulated subsidiary operations can occur in many forms. For example, the unregulated firm could provide services to the utility at above-market rates or, conversely, the utility could provide services to its unregulated affiliates at rates below that which would prevail in an arms-length transaction.

Financial cross-subsidization occurs when the capital structure of the utility operation provides financial strength to the holding company, which, in turn, allows the parent to capitalize its consolidated operations with more debt and less equity (i.e., more cheaply) than they would otherwise be able to do. In other words, the utility (and, thereby, utility ratepayers) shoulders some of the financial risk of the unregulated affiliates by allowing the holding company to be capitalized in a manner that would not prevail in a stand-alone situation.

One way that PNW can maintain a stronger financial profile and offset the increased risks of its unregulated operations and lower equity ratios, is to set rates with a high common equity ratio for its regulated utility operations while simultaneously financing its unregulated operations with a lower equity ratio and a higher percentage of debt capital than would otherwise be possible. That is the essence of financial cross-subsidization. The tangible result of that action is a common equity ratio for PNW that is substantially below that requested by the regulated subsidiary.

Q. HOW DO PINNACLE WEST'S CAPITAL STRUCTURE, AND THE MORE EQUITY-RICH CAPITAL STRUCTRURE REQUESTED BY APS, COMPARE TO THAT UTILIZED IN THE ELECTRIC UTILITY INDUSTRY TODAY?

A. Pinnacle West is capitalized with more common equity than is used in the utility industry today. As shown on page 4 of Schedule 2 attached to my testimony, the median common equity ratio of the electric utility industry is 44%. Dr. Avera's Attachment WEA-8, shows his selected similar-risk sample group. According to AUS Utility Reports, those companies have a current average common equity ratio of 46%. According to the same source, the electric utilities in my sample group have an average common equity ratio of 45.3%. Pinnacle West's current common equity ratio is about 50% of total capital, and APS requests that its rates in this proceeding be set using a common equity ratio of 54.5%. Both of those capital structures contain considerably less debt and more equity that is used on average in the electric industry today.

Q. COMPANY WITNESSES AVERA INDICATES THAT THE CAPITAL STRUCTURES OF HIS SAMPLE GROUP HAVE HIGHER COMMON EQUITY RATIOS THAN THE 46% YOU REPORT. HOW DO YOU RESPOND TO THAT LOGIC?

A. Dr. Avera has not included all the capital issued by his sample group firms in his calculation of common equity; he has excluded short-term debt from that calculation. Dr. Avera reports that the average common equity ratio of his sample group as reported in the August 2005 Value Line is 49%. However, that percentage does not consider the short-term debt those companies have issued. All of the companies in his sample group have short-term debt outstanding and some of those companies have significant amounts of short-term debt outstanding.

For example, the May 12, 2006 edition of Value Line reports that Xcel Energy, one of Dr. Avera's sample companies, has approximately $1.5 Billion in short-term debt. Including that amount in total capital, that company's common equity ratio drops from the 47% calculated without short-term debt to 41.5%. For all the companies in Dr. Avera's sample group, according to the May 12, 2006 Value Line reports on each, the average common equity ratio, considering all capital, is 47.3%.

Also, as I point out in more detail in my discussion of Dr. Avera's cost of capital analysis in Section IV of my testimony, some of the companies selected in his sample group have either substantial unregulated operations (Sempra Energy's unregulated operations contributed 58% of that firms 2005 profits) or very low percentage of electric operations (electric utility operations comprise only 5% of MDU Resources revenues). Those two companies (Sempra and MDU) have the highest common equity ratios in Dr. Avera's sample group. Removing those two companies from the average, even absent consideration of short-term debt, the average common equity ratios of Dr. Avera's remaining companies is 48.6%, according to the May 12, 2006 Value Line report. Considering short-term debt the average common equity ratio of those companies is 45.3% of total capital.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. The Company has recently changed its capital structure by infusing common equity from the parent to the subsidiary, raising APS's common equity ratio from about 45% (where it has resided over the past couple of years) to approximately 54% of total capital at the current time. According to information provided by the Company this recent increase in common equity ratio will not be maintained and the expectation is for lower common equity ratios in the future. The ratemaking common equity ratio requested by the Company in this proceeding is substantially greater than that used, on average, in the electric utility industry today.

Also, APS's parent company, Pinnacle West, which includes unregulated as well as regulated operations is currently capitalized with approximately 50% common equity as a percentage to total capital. Setting rates for a lower-risk utility subsidiary with a capital structure that contains more common equity capital than that used by the parent holding company would be counter to sound financial theory are would lead to financial cross-subsidization of the parent's unregulated operations by the customers of the regulated utility.

I recommend that rates be set using a 50% common equity and 50% long-term debt capital structure. That capital structure has a common equity ratio that is similar to the manner in which the parent company has elected to capitalize its diversified operations and, therefore, will be financially sound for the lower-risk utility. That common equity ratio is higher than the average capital structure existing in the electric and gas utility industry, but that higher common equity ratio (which imparts lower financial risk) can be accounted for in the determination of the appropriate return on equity to be applied to the ratemaking capital structure.

In addition, that capital structure provides additional support for the Company's financial position in that it provides a larger common equity layer than the Company has actually employed for years prior to the third quarter of 2005. The capital structure I recommend also provides a better balance of the interests of ratepayers and stockholders than that requested by the Company, because it is a more economically efficient capitalization. A ratemaking capital structure based on 50% common equity would improve the Company's financial risk position and be less costly to ratepayers than the capital structure containing 54.5% common equity ratio requested by the Company.

Finally, the capital structure I recommend for ratemaking purposes fulfills the Hope and Bluefield requirements of providing an opportunity for the regulated entity to maintain its financial integrity because the debt-to-total capital ratio recommended (50%) is well within the guidelines for its APS's bond rating. As I noted above, for a company with a business risk of "6", like APS, S&P recommends a debt-to-total capital in the range of 48% to 58% for a "BBB" bond rating.

Page 5 of Schedule 2 attached to my testimony shows my recommended ratemaking capital structure and embedded cost rates. The embedded debt cost rates are from the Company's filing, Schedule D-2.

Q. DOES THIS CONCLUDE YOUR DISCUSSION OF CAPITAL STRUCTURE?

A. Yes, it does.

IV. METHODS OF EQUITY COST EVALUATION

A. DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW (DCF) MODEL YOU USED TO ARRIVE AT AN ESTIMATE OF THE COST RATE OF COMMON EQUITY CAPITAL FOR THE ARIZONA PUBLIC SERVICE COMPANY IN THIS PROCEEDING.

A. The DCF model relies on the equivalence of the market price of the stock (P) with the present value of the cash flows investors expect from the stock, providing the discount rate equals the cost of capital. The total return to the investor, which equals the required return according to this theory, is the sum of the dividend yield and the expected growth rate in the dividend.

The theory is represented by the equation,

$$k = D/P + g, \qquad (1)$$

where "k" is the equity capitalization rate (cost of equity, required return), "D/P" is the dividend yield (dividend divided by the stock price) and "g" is the expected sustainable growth rate.

Q. WHAT GROWTH RATE (g) DID YOU ADOPT IN DEVELOPING YOUR DCF COST OF COMMON EQUITY FOR THE COMPANY IN THIS PROCEEDING?

A. The growth rate variable in the traditional DCF model is quantified theoretically as the dividend growth rate investors expect to continue into the indefinite future. The DCF model is actually derived by 1) considering the dividend a growing perpetuity, that is, a payment to the stockholder which grows at a constant rate indefinitely, and 2) calculating the present value (the current stock price) of that perpetuity. The model also assumes that the company whose equity cost is to be measured exists in a steady state environment, i.e., the payout ratio and the expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever. As with all mathematical models of real-world phenomena, the DCF theory does not exactly "track" reality. Payout ratios and expected equity returns do change over time. Therefore, in order to properly apply the DCF model to any real-world situation and, in this case, to find the long-term sustainable growth rate called for in the DCF theory, it is essential to understand the determinants of long-run expected dividend growth.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THE DETERMINANTS OF LONG-RUN EXPECTED DIVIDEND GROWTH?

A. Yes, in Appendix B, I provide an example of the determinants of a sustainable growth rate on which to base a reliable DCF estimate. In addition, in Appendix B, I show how reliance on earnings or dividend growth rates alone, absent an examination of the underlying determinants of long-run dividend growth, can produce inaccurate DCF results.

Q. DID YOU USE A SUSTAINABLE GROWTH RATE APPROACH TO DEVELOP AN ESTIMATE OF THE EXPECTED GROWTH RATE FOR THE DCF MODEL?

A. Yes. I have calculated both the historical and projected sustainable growth rate for a sample of utility firms with similar-risk operations. However, I have not relied solely on that type of growth rate analysis. In addition to the sustainable growth rate analysis, I have also analyzed published data regarding both historical and projected growth rates in earnings, dividends, and book value for the sample group of utility companies. Through an examination of those data, which are available to and used by investors, I am able to estimate investors' long-term growth rate expectations. To that long-term growth rate estimate, I add any additional growth that is attributable to investors' expectations regarding the on-going sale of stock for each of the companies under review.

Q. WHY HAVE YOU USED THE TECHNIQUE OF ANALYZING THE MARKET DATA OF SEVERAL COMPANIES?

A. I have used the "similar sample group" approach to cost of capital analysis because it yields a more accurate determination of the cost of equity capital than does the analysis of the data of one individual company. Any form of analysis, in which the result is an estimate, such as growth in the DCF model, is subject to measurement error, i.e., error induced by the measurement of a particular parameter or by variations in the estimate of the technique chosen. When the technique is applied to only one observation (e.g., estimating the DCF growth rate for a single company) the estimate is referred to, statistically, as having "zero degrees of freedom." This means, simply, that there is no way of knowing if any observed change in the growth rate estimate is due to measurement error or to an actual change in the cost of capital. The degrees of freedom can be increased and exposure to measurement error reduced by applying any given estimation technique to a sample of companies rather than one single company. Therefore, by analyzing a group of firms with similar characteristics, the estimated value (the growth rate and the resultant cost of capital) is more likely to equal the "true" value for that type of operation.

Q. HOW WERE THE FIRMS SELECTED FOR YOUR ANALYSIS?

A. In selecting a sample of utility firms to analyze, I screened all the electric utilities followed by Value Line, because that investor service, in addition to providing a wealth of historical data, provides projected information, which is important in gauging investor expectations. I selected electric companies that had at least 70% of revenues from electric operations, did not have a large price increase due to a pending merger, did not have a recent dividend cut, had stable book values and a bond rating between "A-" and "BBB-". I also selected companies that had generation assets. The screening process for electric utilities is shown on Schedule 3 attached to my testimony. The Companies selected for analysis are: Central Vermont Public Service (CV), FirstEnergy Corp. (FE), Green Mountain Power (GMP), Progress Energy (PGN), Ameren Corp. (AEE), Cleco Corp. (CNL), DPL, Inc. (DPL), Empire District Electric (DPL), Entergy Corp. (ETR), Hawaiian Electric (HE), PNM Resources (PNM), Pinnacle West Capital Corp. (PNW), and Unisource Energy (UNS).[18]

Q. HOW HAVE YOU CALCULATED THE DCF GROWTH RATES FOR THE SAMPLE OF COMPARABLE COMPANIES?

A. Schedule 4 pages 1 through 5, shows the retention ratios, equity returns, sustainable growth rates, book values per share and number of shares outstanding for the comparable gas and electric companies for the past five years. Also included in the information presented in Schedule 4, are Value Line's projected 2006, 2007 and 2009-2011 values for equity return, retention ratio, book value growth rates and number of shares outstanding.

In evaluating these data, I first calculate the five-year average sustainable growth rate, which is the product of the earned return on equity (r) and the ratio of earnings retained

[18] In the Schedules accompanying this testimony, the sample group companies are referred to by their stock ticker symbols, shown in parentheses here.

within the firm (b). For example, Schedule 4, page 4, shows that the five-year average sustainable growth rate for Pinnacle West Capital Corporation (PNW) is 3.22%. The simple five-year average sustainable growth value is used as a benchmark against which I measure the company's most recent growth rate trends. Recent growth rate trends are more investor-influencing than are simple historical averages. Continuing to focus on PNW, we see that sustainable growth in 2005 was only about 1%—above the average growth for the five-year period. However, the return in that year was abnormally low. The historical data for the three years prior to 2005 indicate an a relatively stable growth rate. By the 2009-2011 period, Value Line projects PNW's sustainable growth will reach a level that approximates the recent five-year average—about 3%. These forward-looking data indicate that investors expect PNW to grow at a rate in the future similar to the growth rate that has existed, on average, over the past five years.

At this point I should note that, while the five-year projections are given consideration in estimating a proper growth rate because they are available to and are used by investors, they are not given sole consideration. Without reviewing all the data available to investors, both projected and historic, sole reliance on projected information may be misleading. Value Line readily acknowledges to its subscribers the subjectivity necessarily present in estimates of the future:

> "We have greater confidence in our year-ahead ranking system, which is based on proven price and earnings momentum, than in 3- to 5-year projections." (Value Line Investment Survey, Selection and Opinion, June 7, 1991, p.854).

Another factor to consider is that PNW's book value growth is expected to increase at a 3.5% level over the next five years, after increasing at a 4% rate historically. This information would tend to moderate growth rate expectations. Also, as shown on Schedule 5, page 2, that company's dividend growth rate, which was 6.5% historically, is expected to decrease to a 5% rate of growth in the future—lower than historical levels, but higher than the sustainable growth rate projections. Earnings growth rate data available from Value Line indicate that investors can expect a dramatically different growth rate in the future (6%) than has existed over the past five years (-4.5%). However, Reuters and Zack's (investor advisory services that poll institutional analysts for growth earnings rate projections) project higher earnings growth rate for PNW—7.60% and 6.8%, respectively—over the next five years.

PNW's projected sustainable growth, dividend growth and book value growth point to stable or declining growth in the future. While the earnings growth projections indicate higher growth expectations, those projections may not provide a reliable indication of long-term sustainable growth. Included in Value Line's projected earnings growth are the relatively low earnings of 2005 in the base period. The average return on equity for PNW in Value Line's three-year base period (2003-2005) is 7.5%. The average equity return projected for PNW for the 2009-2011 period is 9.0%—a 20% increase in ROE over the base period. Therefore Value Line's 6% earnings growth projection assumes a 20% increase in the earned equity return, which is not representative of a long-term growth rate trend. A long-term sustainable growth rate of 5.0%, equivalent to the current dividend growth rate projection, is a reasonable expectation for PNW.

Q. IS THE INTERNAL (b x r) GROWTH RATE THE FINAL GROWTH RATE YOU USE IN YOUR DCF ANALYSIS?

A. No. An investor's sustainable growth rate analysis does not end upon the determination of an internal growth rate from earnings retention. Investor expectations regarding growth from external sources (sales of stock) must also be considered and examined. For PNW, page 4 of Schedule 4 shows that the number of outstanding shares increased at a 3.96% rate over the most recent five-year period. However, Value Line expects the number of shares outstanding to remain stable through the 2009-2011 period, bringing the share growth rate down to 0% rate by that time. An expectation of share growth of 1% is reasonable for this company. As shown on page 1 of Schedule 5, because PNW is currently trading at a market price that is greater than book value, issuing additional shares will increase investors' growth rate expectations. Multiplying the expected growth rate is shares outstanding (1%) by (1-(Book Value/Market Value)), increases the growth rate by 0.10%, and the combined internal and external DCF growth rate for PNW is 5.10%.

I have included the details of my growth rate analyses for PNW as an example of the methodology I use in determining the DCF growth rate for each company in the electric industry sample. A description of the growth rate analyses of each of the companies included in my sample groups is set out in Appendix C. Schedule 5, page 1 of Exhibit_(SGH-1) attached to this testimony shows the internal, external and resultant overall growth rates for the electric utility companies analyzed.

Q. HAVE YOU CHECKED THE REASONABLENESS OF YOUR GROWTH RATE ESTIMATES AGAINST OTHER, PUBLICLY AVAILABLE, GROWTH RATE DATA?

A. Yes. Page 2 of Schedule 5 shows the results of my DCF sustainable growth rate analysis as well as 5-year historic and projected earnings, dividends and book value growth rates from Value Line, earnings growth rate projections from Reuters, the average of Value Line and Reuters growth rates and the 5-year historical compound growth rates for earnings, dividends and book value for each company under study.

My DCF growth rate estimate for all the electric utility companies included in my analysis is 5.10%. This figure is higher than Value Line's projected average growth rate in earnings, dividends and book value for those same companies (4.40%) and is well above the five-year historical average earnings, dividend and book value growth rate reported by Value Line for those companies (2.59%). My growth rate estimate for the electric companies under review is below the analysts' consensus earnings growth rate projections—below earnings growth projection for those companies, 5.96% and 6.4% (Reuters and Zack's respectively). Also, my growth rate estimate is above the projected dividend growth rate of the sample companies, 3.96%.

Q. DOES THIS CONCLUDE THE GROWTH RATE PORTION OF YOUR DCF ANALYSIS?

A. Yes, it does.

Q. HOW HAVE YOU CALCULATED THE DIVIDEND YIELDS?

A. I have estimated the next quarterly dividend payment of each firm analyzed and annualized them for use in determining the dividend yield. If the quarterly dividend of any company was expected to be raised in the next quarter (4th quarter 2006), I increased the current quarterly dividend by (1+g). For the utility companies in the sample groups, a dividend adjustment was unnecessary for most of the companies under study because they either recently raised their dividend or were not projected to raise the dividend in 2006. Companies requiring dividend adjustments were First Energy and Pinnacle West.

The next quarter annualized dividends were divided by a recent daily closing average stock price to obtain the DCF dividend yields. I use the most recent six-week period to determine an average stock price in a DCF cost of equity determination because I believe that period of time is long enough to avoid daily fluctuations and recent enough so that the stock price captured during the study period is representative of current investor expectations.

Schedule 6 contains the market prices, annualized dividends and dividend yields of the utility companies under study. Schedule 6, page 1, indicates that the average dividend yield for the sample group of electric companies is 4.33%. The year-ahead dividend yield projection for the electric utility sample group published by Value Line is 4.40% (Value Line, *Summary & Index*, June 30, 2006). By that measure, my dividend yield calculation is representative of investor expectations.

Q. WHAT IS YOUR COST OF EQUITY CAPITAL ESTIMATE FOR THE ELECTRIC AND GAS UTILITY COMPANIES, UTILIZING THE DCF MODEL?

A. Schedule 7 shows that the average DCF cost of equity capital for the group of electric utilities is 9.44%.

B. CORROBORATIVE EQUITY COST ESTIMATION METHODS

Q. IN ADDITION TO THE DCF, WHAT OTHER METHODS HAVE YOU USED TO ESTIMATE THE COST OF EQUITY CAPITAL FOR ARIZONA PUBLIC SERVICE COMPANY?

A. To support and temper the results of my DCF analysis, I have used three additional econometric methods to estimate the cost of equity capital for a group of firms similar in investment risk to APS. The three methodologies are: 1) the Capital Asset Pricing Model (CAPM), 2) the Modified Earnings-Price Ratio (MEPR) analysis, and 3) the Market-to-Book Ratio (MTB) analysis. The similar risk sample group of firms analyzed with these three methods is the same as that selected for the DCF analysis, discussed previously. The theoretical details of each of those analyses are contained in Appendix D, attached to this testimony. The actual calculations and data supporting the results of each of these models are shown in the attached Schedules.

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis. The average beta coefficients for the electric utility sample group was 0.83. Schedule 8 shows a CAPM cost of capital for the electric companies ranging from 9.23% to 10.56%.

Schedules 9 and 10 shows the theoretical basis and the data and calculations, respectively, for the Modified Earnings Price Ratio (MEPR) analysis. The MEPR analysis indicates a current cost of equity capital for electric companies in a narrow range from 8.79% to 9.13%. Finally, Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital for the electric utility companies of 9.31% (near-term) to 9.38% (long-term).

C. SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC UTILITY COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table below.

METHOD	Electric Utility Companies
DCF	9.44%
CAPM	9.23%/10.56%
MEPR	9.13%/8.79%
MTB	9.31%/9.38%

For the electric utility sample group, the DCF result is 9.44%. In addition, the corroborating cost of equity indications (MEPR, MTB, and CAPM) indicate that DCF result is reasonable. Averaging the lowest and highest results of all the corroborative analyses for the electric companies produces and equity cost range of 9.11% to 9.69%, with a mid-point of 9.40%, only 4 basis points below the DCF result.

Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company like Arizona Public Service, facing similar risks as this group of electric utilities, ranges from 9.25% to 9.75%, with a mid-point of 9.50%.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED BEFORE DETERMINING A POINT-ESTIMATE FOR APS WITHIN A REASONABLE RAGE FOR SIMILAR-RISK FIRMS?

A. Yes. First, the electric sample group companies have similar operating risk to APS. The average S&P business risk score of my sample of electric utilities is 6—the same as that for APS. Therefore, on that basis there would be no reason to adjust the equity return from the mid-point of a reasonable range. However, because the capital structure I recommend for ratesetting purposes contains considerably more common equity and less debt than average for the sample group, APS, prospectively will have less financial risk than the sample group and should be awarded an equity return below the mid-point of a reasonable range.

Q. IS THERE A RECOGNIZED METHOD WITH WHICH DIFFERENCES IN FINANCIAL RISK CAN BE QUANTIFIED?

A. Yes. The cost of equity capital is affected by the capital structure a company employs. When a company increases the proportion of debt in its capital structure, it increases the riskiness of its equity. Financial risk (created by the use of debt in the capital structure) causes investors to demand a higher rate of return; that is, financial risk increases the cost of equity capital.

The impact of debt leverage on the cost of equity capital can be approximated through an examination of the changes in beta, which occur when leverage is increased or decreased. The Value Line betas for the sample companies used in my cost of capital analysis in this proceeding reflect the market's (investors') perception of both the business risks and the financial risks of a firm. That is, one portion of the beta of a firm is related to the business risk of the firm (the risk inherent in its operations) and one portion of the beta is related to the financial risk of that firm (the risk associated with the use of debt). Therefore, if a firm elects to finance its operations with debt as well as equity, the beta coefficient of that firm will reflect both the business and financial risk. When a firm uses debt to finance its operations, the beta can also be referred to as a "levered" beta (i.e., a beta coefficient that includes the impact of debt leverage).

The average beta coefficient of the sample group of utilities can be "unlevered." That is, the beta-risk related to the level of debt capital used by the firm can be removed. "Unlevering the betas" amounts to estimating what the average beta would be if the companies were financed entirely with equity capital. Equation (2) is used to estimate the unlevered beta for a firm or a group of similar-risk firms.[19]

$$\beta_U = \frac{\beta_{Measured}}{(1+(1-t)D/E)} \qquad (2)$$

Equation (2) indicates that an estimate of the unlevered beta (β_U) of a firm can be calculated by dividing the measured beta ($\beta_{Measured}$, e.g. the beta coefficient reported by investor services such as Value Line) by one plus the average debt-to-equity ratio, adjusted to account for taxes. The debt-to-equity ratio is measured using the average market value of the sample group's common equity capital. Once the unlevered beta for the firm (or, in this case, for the sample group of market-traded utility companies) is calculated, the beta coefficient is "re-levered" and adjusted to conform to the less leveraged capital structure of APS, which contains 50% common equity. The formula used to "re-lever" the utility betas is shown below.

$$\beta_{Relevered} = \beta_U(1+ (1-t)D/E) \qquad (3)$$

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the unlevered beta coefficient of those

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[19]Equation (1) is a version of the Hamada equation which combines the Miller-Modigliani theories regarding capital structure and the logic of the CAPM: Hamada, R.S., "Portfolio Analysis, Market equilibrium and Corporation Finance," *Journal of Finance*, March 1969, pp. 13-31.

firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, a decrease in beta of 0. 079, due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of

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[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES YOUR 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, it is often said that flotation costs associated with common stock issues are exactly like flotation costs associated with bonds. That is not a correct statement because bonds have a fixed cost and common stock does not. Moreover, even if it were true, the current relationship between the electric utility sample group's stock price and its book value would indicate a flotation cost reduction to the market-based cost of equity, not an increase.

When a bond is issued at a price that exceeds its face (book) value, and that difference between market price and the book value is greater than the flotation costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt.

In the current economic environment for the electric utility common stocks studied to determine the cost of equity in this proceeding, those stocks are selling at a market price 69% above book value. (Exhibit__(SGH-1), Schedule 4, p. 1) The difference between the market price of electric utility stock and book value dwarfs any issuance expense the companies might incur. If common equity flotation costs were exactly like flotation costs with bonds and if an explicit adjustment to the cost of common equity were, therefore necessary, then the adjustment should be downward, not upward.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. As noted, the companies under review are selling at a substantial premium to book value. Therefore, every time a new share of that stock is sold, existing shareholders realize an *increase* in the per share book value of their investment. No dilution occurs, even without any explicit flotation cost allowance.

Third, the vast majority of the issuance expenses incurred in any public stock offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

In addition, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that understanding, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses related to increases in stock outstanding is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[22]. There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs that, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs that lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's INTEGRATED UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.25%?

A. Schedule 13 attached to my testimony shows that an equity return of 9.25%, operating through an appropriate ratemaking capital structure of 50% equity and 50% debt, and the Company's requested embedded capital cost rates, produces an overall return of 7.33% for

[22] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

APS. Schedule 13 also shows that a 7.33% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.85 times.

According to APS's 2005 S.E.C. Form 10-K (Exhibit 12), the pre-tax interest coverage over the past five years has averaged 2.94x and has ranged from 2.81x to 3.17x. The return I recommend would allow the Company the opportunity to improve its historical average interest coverage. Therefore, the equity return I recommend fulfills the legal requirement of Hope and Bluefield of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

V. COMPANY COST OF CAPITAL TESTIMONY

Q. HOW HAS COMPANY WITNESS AVERA ESTIMATED THE COST OF EQUITY CAPITAL IN THIS PROCEEDING?

A. Company witness Avera has analyzed the cost of equity capital for Arizona Public Service using a standard DCF analysis as well as several risk premium analyses (bond yield plus risk premium as well as Capital Asset Pricing Model analyses). As I will explain in detail below, Dr. Avera's Risk Premium analyses are flawed and produce equity cost estimates that are biased upward.

Q. PRIOR TO DISCUSSING ANY INFIRMITIES THAT EXIST IN DR. AVERA'S COST OF EQUITY ANALYSIS, DO YOU HAVE ANY GENERAL COMMENTS REGARDING HIS TESTIMONY?

A. Yes. Dr. Avera's DCF results indicate that Arizona Public Service's cost of equity capital is 9.0% (Avera Direct, p. 42). Although that estimate is now out of date and, using his same methodology, more recently available data indicates a slightly higher cost of equity, as I will discuss subsequently, Dr. Avera suggests that the Commission ignore his DCF results. He opines that his DCF results are "different" from his other results and, for that reason, his

DCF results (not his other, higher results) should not be utilized. He also indicates that the near-term direction of the economy is "uncertain" and DCF growth rates will be understated because of that reason.

Unfortunately, Dr. Avera has it backward. If there is disparity in his equity cost estimates, then it is his higher Risk Premium results that should be questioned, not his DCF. For example, as I will demonstrate below, in producing his high CAPM results, Dr. Avera has used an exaggerated market risk premium which is substantially in excess of long-term historical risk premiums as well as the current expectations for future risk premiums. While Dr. Avera's DCF is somewhat understated due to the use of stale data, that methodology is applied in a reasonable manner—i.e., one which has long been accepted and used in regulation. Therefore, it is his DCF that provides the best indication of the cost of equity, not his exaggerated Risk Premium analyses.

On the topic of the economy, Dr. Avera's opinion that the current recovery is "uncertain" is not widely held. In Section I of this testimony, I cited Value Line's most recent Quarterly Review of the U.S. economy. The current economic expansion has not seen a great flurry of activity, however, it is proceeding at a steady and respectable pace. Further, Value Line informs its subscribers that it expects 3% GDP growth through 2007.[23] An economic growth expectation of 3%, in my view, does not constitute an "uncertain" economic environment.

Also, I have testified in several proceedings with Dr. Avera and am familiar with the equity cost estimation methods he has used over time. Dr. Avera began, in the early 1990s, to adopt the position that the DCF could not accurately estimate the cost of equity, although his reasons for reaching that conclusion have changed over the years. When he first began to discuss the "unreliability" of the standard DCF analysis, Dr. Avera's rationale was that the volatility of stock prices in the late 1980s and early 1990s made standard DCF equity cost estimates unreliable. Then, in the later 1990s, Dr. Avera's anti-DCF rationale was that the changing nature of electric regulation had made the DCF unreliable. During that period

[23] Value Line *Selection & Opinion*, May 26, 2006, p. 1111.

of time, he did not provide a standard DCF analysis, and, instead, presented a multi-stage DCF analysis.

Regardless of the reasons he has provided over the years for downplaying the equity cost estimates produced by a DCF analysis, the results of that rationale have been consistent—higher equity cost estimates. In other words, no matter what the cause—stock price volatility, restructuring, or now an uncertain economy—the standard DCF, in Dr. Avera's view, produced results that he characterized as being too low.

Dr. Avera recognizes at page 42 of his Direct Testimony, that "the DCF model has been routinely relied on in regulatory proceedings" as an indication of the cost of equity capital. The DCF is, by far, the most utilized method to estimate equity costs in regulated industries for one simple reason—it works, and it works well. Dr. Avera's cautions to the Commission regarding reliance on his DCF results notwithstanding, his DCF analysis provides the most accurate estimate of Arizona Public Service's cost of equity capital presented by the Company in this proceeding.

Q. HAS THE "RELIABILITY" OF DCF EQUITY COST ESTIMATES BEEN QUESTIONED BY UTILITY-SPONSORED RATE OF RETURN WITNESSES IN OTHER REGULATORY PROCEEDINGS?

A. Yes. As capital costs have declined during the last decade or more and the DCF has (appropriately) produced lower and lower equity cost estimates, it has become the norm, in my experience, that utility-sponsored rate of return witnesses attempt to convince regulators that standard-DCF results are unacceptably low for one reason or another.

Q. HAVE THOSE WITNESSES BEEN SUCCESSFUL IN THEIR ENDEAVOR TO PERSUADE COMMISSIONS TO REDUCE THEIR USE OF THE DCF IN REGULATION?

A. No, in my experience, they have not, even though those efforts have been on-going for more than a decade. The standard DCF continues to be the most widely used equity cost estimation methodology used in regulation. That experience is confirmed by an article appearing in the mid-1990s in Public Utility Reports, entitled "Cost of Equity Determinations—State Regulators Turn Back Challenges to the DCF Model:"

> "The discounted cash flow (DCF) model, the methodology most frequently relied upon to establish authorized ROE, has often engendered spirited debate over the technical aspects of its application. Of late, however, some utilities have shifted the focus of the debate, urging that the DCF model no longer produces reasonable results....
>
> Despite utility claims in numerous rate proceedings that the DCF model is producing unreasonably low estimates of investor-expected return on investment in utility equity, state regulators have not reduced their reliance on the model as the primary tool in setting rate of return. In fact the opposite may be true." (148 P.U.R. 4th, Advance Sheets, p. i, iii (March 4, 1994)).

The article concludes by listing states in which regulators have stated their intent to continue to rely on the DCF: Arizona, California, Colorado, Connecticut, District of Columbia, Florida, Illinois, Maryland, Massachusetts, Minnesota, Pennsylvania, Rhode Island and Utah. It has been my experience that, since that article was written, this Commission continues to rely primarily on the results of DCF analyses.

Q. MR. HILL, IS IT YOUR TESTIMONY THAT THE DCF IS INFALLIBLE AND IS THE ONLY EQUITY COST ESTIMATION METHODOLOGY THAT SHOULD BE CONSIDERED BY REGULATORS?

A. No. I believe the DCF is the most reliable equity cost estimation methodology, is less subject to manipulation than risk premium methods, and should provide the primary indication to regulators of the market-based cost of equity capital—the return that should be allowed regulated firms. However, no simple algebraic representation of complex investor behavior is infallible, and it is reasonable to estimate the cost of common equity using other methodologies. I have been consistent in my approach to estimating the cost of equity capital, using other methods to support and temper the results of my DCF analysis, as I do in this testimony. As I noted previously, my three additional cost of equity analyses bracket my DCF result and support its reasonableness. However, it is most important that the other equity cost methods in addition to the DCF must be applied in a theoretically responsible manner—something I believe Dr. Avera has failed to do in his CAPM analysis in this proceeding.

Q. DO YOU HAVE ANY COMMENTS REGARDING DR. AVERA'S SELECTION OF COMPANIES IN HIS SIMILAR SAMPLE GROUP?

A. While some of the companies in Dr. Avera's sample group are also in my own, I do have some concerns with his selection process. For one thing, Dr. Avera appears to have been unconcerned about the amount of revenues generated by regulated electric operations of the companies he selected. Dr. Avera's sample group contains Black Hills Corp., MDU Resources and Sempra Energy; mine does not. AUS Utility Reports (June 2006) indicates that only 5% of MDU Resources revenues and 22% of Black Hills Corp's revenues are from regulated electric utility operations. Also, Black Hills Corporation mines coal, and has an oil and gas exploration business as well as a telecommunications business. MDU Resources has gas pipeline, oil and gas production, mining and construction materials production, utility line maintenance and independent power production businesses. In addition, Value Line reports in its May 12, 2006 edition of *Ratings & Reports*, that 58% of Sempra Energy's profits last year came from its unregulated businesses.

My point here is that with substantial unregulated operations, the cost of capital for those companies would tend to overstate that appropriate for an electric utility operation like Arizona Public Service Company. Due to additional unregulated company risk included in his sample group, Dr. Avera's equity cost estimate will overstate the cost of equity capital for APS, even if the equity cost estimation methods are reasonably applied.

Q. YOU MENTIONED THAT DR. AVERA'S 9.0% DCF RESULT IS NOW SOMEWHAT UNDERSTATED. CAN YOU ELABORATE?

A. Yes. Dr. Avera's DCF methodogy relies on published information in Value Line and earnings growth rate projections from three different investor services. It is a simple matter to update those data and analyze what a more recent version of his DCF analysis would produce. If Dr. Avera updated his DCF analysis it would be similar to his initial estimate, but somewhat higher.

Dr. Avera's DCF dividend yield is derived in his Schedule WEA-1 and is based on the data published in the October 14, 2005 Value Line *Summary & Index*. He calculates the year-ahead dividend yield to be 3.5% for his sample group of companies. Using the most recent *summary & Index* available at the time of the preparation of this testimony (June 30, 2006) the average dividend yield of Dr. Avera's companies has risen to 3.8%, as shown in the Table I below.

TABLE I

DR. AVERA'S DIVIDEND YIELD – UPDATED

Company	**Stock Price**	**Estimated Dividends Next 12 Mos.**	**Implied Dividend Yield**
Black Hills Corp.	$ 33.13	$ 1.34	4.0%
Edison International	$39.36	$1.12	2.8%
Hawaiian Electric	$ 27.00	$ 1.24	4.6%
IDACORP, Inc.	$ 33.40	$ 1.20	3.6%
MDU Resources Group	$ 34.93	$ 1.00	2.3%
PNM Resources Group	$ 25.82	$ 0.88	3.4%
Pinnacle West Capital	$ 39.08	$ 2.05	5.2%
Puget Energy, Inc.	$ 21.21	$ 1.00	4.7%
Sempra Energy	$ 44.46	$ 1.22	2.7%
Xcel Energy	$ 19.01	$ 0.89	4.7%
Average			**3.8%**

Data from the Value Line Investment Survey, Summary and Index (6/30/06).

Q. HOW DID DR. AVERA CALCULATE HIS DCF GROWTH RATE?

A. Dr. Avera presents most of his DCF growth rate data in his Schedule WEA-2. Those data are earnings projections from investor advisory services (Value Line, IBES, First Call, and Reuters). Dr. Avera also presents historical earnings data for his sample group of companies. In prior testimony, Dr. Avera also reviewed historical earnings data in determining his DCF growth rate; he omits any such analysis here. Dr. Avera's earnings growth projections range from 5.4% to 5.7%.

In his Schedule WEA-5, Dr. Avera provides a sustainable growth rate analysis based on Value Line data that indicates an average growth rate projection of 4.6% for his sample group of companies. That 4.6% sustainable growth rate result is below 5.4% to 5.7% projected earnings growth rates presented by Dr. Avera. However, in reviewing his data, Dr. Avera selected a growth rate range of 5.5% as his DCF growth rate. It appears that Dr. Avera's DCF growth rate selection was heavily influenced by his projected earnings growth rates.

While I would agree with Dr. Avera that investors would consider projected earnings growth in determining their required return, I disagree that investors would rely exclusively on that type of information, ignoring other available data that may indicate lower long-term growth. Nevertheless, that appears the operative assumption of Dr. Avera's DCF growth rate analysis here.

Q. WHAT ARE THE RESULTS OF DR. AVERA'S DCF GROWTH RATE METHODOLOGY WHEN HIS DATA ARE UPDATED?

A. Shown in Table II on the next page are Dr. Avera's updated DCF growth rate data. I do not have access to Standard & Poors Earnings Guide for IBES projected earnings growth rates. The other data are the same as that used by Dr. Avera, only published more recently.

TABLE II

DR. AVERA'S DCF GROWTH RATES - UPDATED

	Projected			
Company	**Value Line**	**Zacks**	**First Call**	**Reuters**
Black Hills Corp.	6.5%	6.0%	4.5%	6.0%
Edison International	7.0%	7.7%	7.0%	7.75%
Hawaiian Electric	3.0%	5.2%	3.0%	2.9%
IDACORP, Inc.	4.5%	4.7%	5.0%	4.75%
MDU Resources Group	8.0%	8.3%	8.0%	6.85%
PNM Resources Group	5.5%	8.3%	8.5%	11.45%
Pinnacle West Capital	6.0%	6.8%	6.0%	7.6%
Puget Energy, Inc.	5.0%	7.0%	4.0%	5.14%
Sempra Energy	5.5%	5.4%	4.8%	5.96%
Xcel Energy	6.0%	4.5%	4.5%	4.5%
Average	**5.7%**	**6.4%**	**5.5%**	**6.3%**

Value Line Investment Survey, Ratings & Reports, May 12, 2006
First Call, Reuters, Zack's from on-line services, July 12, 2006

Table II shows that the earnings growth rate projections published by the investor services have increased slightly from those shown in Dr. Avera's testimony. The more recent average of those forward-looking earnings growth rates is 6.0% versus his original 5.5%. Simply adding the more current dividend yields to the more current earnings growth projections would produce a DCF result of 9.8% for Dr. Avera's sample companies.

However, as I noted above and discuss in more detail in Appendix B, earnings growth is not the only growth rate projection available to investors. Dr. Avera's original sustainable growth rate analysis produced a result of 4.6%. Using the data from the most recent Value Line indicates a projected growth rate for his sample group of 5.2%. That result is 80 basis points below the 6% average earnings growth rate shown above in Table II.

Also, Value Line provides projections for dividends and book value for each of the companies it follows and those data are also available to (and presumably used by) investors. However, Dr. Avera's DCF technique elects to ignore those data. Table III below shows Value Line's most recent three- to five-year projections for earnings, dividends and book value for all of the Companies in Dr. Avera's sample group.

TABLE III.

VALUE LINE PROJECTIONS

	Earnings	**Dividends**	**Book Value**
Black Hills Corp.	6.50%	3.00%	4.00%
Edison International	7.00%	nmf	8.50%
Hawaiian Electric	3.00%	0.00%	2.50%
IDACORP, Inc.	4.50%	-2.00%	3.00%
MDU Resources Group	8.00%	5.00%	15.00%
PNM Resources Group	5.50%	8.50%	4.00%
Pinnacle West Capital	6.00%	5.00%	3.50%
Puget Energy, Inc.	5.00%	1.00%	4.00%
Sempra Energy	5.50%	4.50%	11.00%
Xcel Energy	6.00%	5.50%	3.00%
Averages	**5.70%**	**3.39%**	**5.85%**
Overall Average		**4.98%**	

In DCF theory, the dividends, earnings and book value are assumed to grow at the same rate over the long term. Therefore, it is reasonable to consider the average of those projected growth rate parameters as an indicator of sustainable long-term growth for the DCF. Table III shows that average to be about 5% for Dr. Avera's companies. That projected growth is similar to the current sustainable growth rate, according to Dr. Avera's calculation method, 5.2%. Both of those projected growth rates are well below the 6% earnings growth rate average for Dr. Avera's companies, and suggest that a DCF based only on projected earnings growth would overstate investors' required return (the cost of common equity capital).

In sum, Dr. Avera's DCF methodology currently indicates a higher cost of equity than the 9.0% he presented in his Direct Testimony. The current dividend yield for his sample group is 3.8%. Taking into account all the available data and not relying only on earnings, Dr. Avera's projected growth rates range from 5.0% to 6.0%. In combination with a dividend yield of 3.8%, those growth rates describe a cost of equity range for APS of 8.8% to 9.8%, the mid-point of which is 9.3%. My DCF estimate in this proceeding is 9.44%. An update of Dr. Avera's DCF methodology tends to confirm my own equity cost estimate in this proceeding.

Q. DOES THIS CONCLUDE YOUR COMMENTS ON THE COMPANY'S DCF ANALYSIS?

A. Yes.

Q. WHAT OTHER EQUITY COST ESTIMATION ANALYSES DOES DR. AVERA PRESENT IN HIS TESTIMONY IN THIS PROCEEDING?

A. Dr. Avera utilizes three kinds of risk premium analyses in his Direct Testimony in this case: 1) a comparison of authorized rates of return to prevailing interest rates, 2) historical realized rates of return, and 3) Capital Asset Pricing Model analyses (historical and projected). Also in all of his risk premium analyses, Dr. Avera presents his results based on current bond yields and projected bond yields. In my view, only the use of current bond yields (i.e., the embodiment of investors' current expectations for the future) provides a reliable estimate of the cost of equity capital. What the bond yields might or might not be a year from now is not a basis for estimating the current cost of common equity capital.

Q. PLEASE EXPLAIN WHY CURRENT BOND YIELDS OFFER THE BEST INDICATION OF THE COST OF CAPITAL TO BE USED IN A RATESETTTING PROCEEDING SUCH AS THIS.

A. Investors are aware of current projections regarding the expectations for the economy and the level of interest rates and incorporate those expectations into the price they are willing to provide for bonds and, thus, the bond yield. One of the most widely-accepted tenets of modern finance—the efficient market hypothesis—holds that all publicly available information is included in security prices. That includes interest rate forecasts. Therefore, the current yield does not need to be adjusted again for the same expectations that are already included by investors. Basing risk premium estimates on projected bond yields would be similar to basing DCF equity cost estimates on projected stock prices. Dr. Avera has not attempted to base DCF estimates on projected market prices and the Commission should not rely on his equity cost estimates that rely on projected bond yields.

Q. HAS DR. AVERA CONSISTENTLY TESTIFIED IN FAVOR OF USING RISK PREMIUM ANALYSES TO ESTIMATE THE COST OF EQUITY?

A. No. In testimony on behalf of Southwest Bell Telephone before the Federal Communications Commission (FCC; CC Docket No. 84-800) in a proceeding in which the FCC was seeking comments as to whether or not an equity cost represcription process using the risk premium would be advisable, Dr. Avera testified against the use of the risk premium.

In the executive summary of his testimony before the FCC, Dr. Avera presented the overall conclusion of his research on the risk premium:

> "Based on a review of other empirical studies and our independent research, we concluded that a formula predicated upon the bond-yield-plus-risk-premium methodology would not provide an adequate measure of the changes in the cost of equity during the time intervals between prescriptions since there would be no confidence that the resulting interim cost of equity would be reasonably accurate over a particular time period." (Ibid., p.2)

In his testimony on the risk premium in the instant case, Dr. Avera's CAPM analysis relies, in part, on a measure of the market risk premium as the difference between a forward-looking equity model (a DCF) and bond yields. Reviewing that type of study in 1984, Dr. Avera testified before the FCC as follows:

> "The studies of equity risk premium behavior that employ forward-looking estimates of the cost of equity have obvious advantages over the use of historical realized rates of return. Nonetheless, the results must be interpreted carefully. The cost of equity estimation models and associated growth projection inputs are necessarily applied in a mechanistic fashion. Estimating the cost of equity at any particular point in time is clearly a difficult exercise; accordingly, utilizing a single formula with mechanistically derived inputs over a number of periods to generate forward-looking cost of equity estimates is fraught with potential inaccuracies." (Ibid., p. 12)

Another type of risk premium methodology presented by Dr. Avera in this proceeding is one historical difference between stock returns and bond returns. Before the FCC in the case cited above, Dr. Avera's comments on historical risk premium studies were less than complimentary:

> "While the results of empirical analyses based on average realized rates of return may be indicative of return relationships over a long historical horizon, such studies are of little value in assessing the behavior of equity risk premiums over time. Even as a measure of equity risk premiums at a particular point in time, the use of historical average realized rates of return has been criticized on a number of grounds (e.g., the estimated premiums vary significantly depending upon the method of averaging and the time intervals employed). Perhaps of more concern for present purposes is the fundamental assumption upon which studies using the historical realized rates of return approach rests. Realized rates of return for common stocks over any particular holding period will inevitably be different from what investors actually expected; indeed, such deviations of realized return versus expected rates of return are what cause holding common stock to be risky." (Ibid., p. 9)

Other financial authors have also noted the drawbacks of risk premiums based on historical realized rates of return:

> "There are both conceptual and measurement problems with using I&S [Ibbotson and Sinquefield] data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed,

> evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome." ("The Risk Premium Approach to Measuring a Utility's Cost of Equity," Brigham, Shome and Vinson, Financial Management, Spring 1985, p. 34)

This Commission, to my knowledge, has not relied on risk premium analysis as a primary indicator of equity capital costs, and has, instead relied primarily on the DCF. Dr. Avera's testimony on the subject of risk premium in this case fails to provide the Commission with any new evidence to justify a change from that position, in my view. Moreover, his prior testimony before the FCC provides evidence that the risk premium studies on which Dr. Avera relies in this proceeding "would not provide an adequate measure of... the cost of equity" (Avera Testimony, FCC Docket. 84-800, p. 2).

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE SPECIFICS OF EACH OF DR. AVERA'S RISK PREMIUM ANALYSES?

A. Dr. Avera's historical realized risk premium analysis is shown in his Schedule WEA-5 and compares the annual earned return of the S&P Electric Utilities to the annual return on A-rated utility bonds from 1945 through 2004. Those data indicate that the average yield differential over that time is 4.04%. When that differential is added to an August 2005 BBB bond yield, it produces an equity cost estimate of 9.8%. The current BBB utility bond yield is 6.60%. That more up-to-date yield indicates a current cost of equity for Dr. Avera's sample group, based on this type of risk premium analysis, of 10.64%.

While that is well below Dr. Avera's equity return recommendation in this proceeding, it substantially overstates the DCF cost of equity capital. Moreover, the risk premium data on which it is based (Dr. Avera's Schedule WEA-5) illustrates an important shortcoming of risk premium analyses. The measured risk premium is sensitive to the choice of estimation period and the end points of that period; and most importantly, the choice of those endpoints is often arbitrary. In Dr. Avera's analysis, although he does not provide that information, I assume his study period begins in 1946 because that's when data were first available, not because of some economic importance to that date. Nevertheless the start and end date of the study period have significant impact on the outcome of the analysis.

Also, as shown in Table IV below, taken from Dr. Avera's Schedule WEA-7, risk premiums are not static and change over time. Since the beginning point of Dr. Avera's historical risk premium study, 1945, the realized return difference between utility stocks and utility bonds had declined.

TABLE IV

HISTORICAL RISK PREMIUM DATA

Time Period	Stock Return	Bond Return	Risk Premium
1946-2004	10.81%	6.74%	**4.07%**
1956-2004	10.96%	7.67%	**3.07%**
1966-2004	10.25%	9.11%	**0.81%**
1976-2004	13.32%	11.55%	**1.33%**
1986-2004	12.13%	11.46%	**-0.07%**
1996-2004	10.57%	9.23%	**-0.24%**

Data from Avera Schedule WEA-5.

Between 1946 and 2003, as Dr. Avera reports, utility stocks earned a return about 4% higher than bonds. Between 1956 (ten years later) and 2003, that return difference fell to 3%. Moving forward to the 1966 to 2003 period (roughly the past 40 years) that return differential fell to less than 1%, remained about 1% over the past thirty years, and then continued to decline during the 1980s and 1990s until the risk premium was actually negative.

Therefore, while Dr. Avera's 1946-2003 risk premium of 4% produces an equity cost estimate in the mid-10% range when combined with current bond yields, if investors are influenced by more recent historical information, it is reasonable to believe that the expected return premium for utility stock above utility bonds is much smaller than the 4%

used by Dr. Avera. So, too, would be the resultant cost of equity estimate.

Finally, on this point, as I discussed in detail in Section I of my testimony, according to research in the field of financial economics over the past decade, the risk premium expectations for the future are lower than they have been in the past. That lower risk premium expectation would comport with investors' more recent experience as shown in Table IV, above, for the last thirty years of data.

Q. WHAT ARE YOUR COMMENTS REGARDING DR. AVERA'S CAPITAL ASSET PRICING MODEL ANALYSIS?

A. Dr. Avera has performed two types of CAPM analyses. One is based on long-term historical market return data published by Ibbotson Associates, shown in his Schedule WEA-7. The other is based on a projected DCF return on the broad stock market, and is shown in his Schedule WEA-6. Both results are adjusted to include projected interest rates. I have previously discussed the flaws in using projected interest rates to estimate the current cost of equity and will confine my comments here to the flaws in Dr. Avera's current CAPM estimates.

The primary flaw in Dr. Avera's CAPM analysis is the market risk premium he uses. Regarding the market risk premium, Dr. Avera has used 7.2% for his historical market risk premium and 9.0% for his forward-looking estimate.

Q. WHAT ARE YOUR COMMENTS REGARDING THE SPECIFICS OF DR. AVERA'S TWO MARKET RISK PREMIUMS?

A. First, Dr. Avera uses a long-term historical differential reported by Ibbotson Associates between the return on stocks and the yield on bonds. That is reported as 7.2% for the 1926-2004 period. However, Ibbotson Associates also publish the differential between the return on stocks and the return on bonds. That figure is reported as 6.6% for the 1926-2004 period. The rationale for using the 7.2% historical figure is that there have been unanticipated gains with bond investments and the historical yields better represents investor expectations. However, there is no analog (i.e., yield) for stocks, and the metric used by Ibbotson Associates is the earned return on either the S&P 500 or the NYSE index. The return series are better balanced and have more meaning for determining expectations if earned returns are used for both series. The difference between the earned return series is 6.6% (i.e., the average historical return on stocks has been 6.6% higher than the average historical return on bonds). However, Dr. Avera has elected to use the 7.2% based on bond yields.

However, as I noted in Section I of this testimony, a recent paper published by Ibbotson in the Financial Analysts' Journal indicates that the maximum expected market risk premium (the return equity investors expect over bond yields) is 6%, not the 7.2% used by Dr. Avera in his testimony.[24] In that recently published paper, Dr. Ibboston discusses the current theoretical debate over the market risk premium. That debate centers on the fact that recent studies have shown that long-term historical risk premiums overstate current investor expectations. As Ibbotson notes, the current research indicates that the market risk premium going forward ranges from 0% to a maximum of about 5% (op cit., pp. 88, 89). Ibbotson disagrees with that current research and provides his analysis of the issue, which shows a prospective market risk premium to range from 4% (based on a geometric average) to 6% (based on an arithmetic average).

The point here is simple. Dr. Avera has selected a particular historical market risk premium for his CAPM because Ibbotson published it, but, 1) Ibbotson also publishes a 6.6% risk premium in the same publication and 2) in a more current publication, Ibbotson indicates the prospective market risk premium is 6% (at the upper end), not the 7.2% Dr. Avera has elected to use in this proceeding.

Second, Dr. Avera has also constructed a forward-based market risk premium based on a DCF analysis of the S&P 500. Dr. Avera also advises the Commission to be cautious about relying on DCF estimates; yet, he bases his preferred risk premium methodology, in part, on a DCF analysis. If the DCF provides a reasonable estimate of the expected return

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[24] Ibbotson, R., Peng, C., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts' Jounal*, January/February 2003, pp. 88-98.

for the S&P 500 it is reasonable to believe it would provide an accurate estimate of the cost of equity for utilities. This presents a conflict of logic in Dr. Avera's testimony.

Also, Dr. Avera's 9.0% risk premium that results from his forward-looking analysis is substantially in excess of any other indication of forward-looking risk premium currently being discussed in the theoretical financial literature. In fact, the current consensus is that forward risk premiums are likely to be substantially lower than historical risk premiums. However, Dr. Avera's methodology produces the reverse result.

Q. WHAT ARE YOUR COMMENTS REGARDING DR. AVERA'S OTHER RISK PREMIUM ANALYSIS—THE "ALLOWED RETURN" RISK PREMIUM?

A. Dr. Avera's other risk premium analysis is one that compares historical allowed equity returns to annual average bond yields. That study indicates that the average risk premium between allowed returns for electric utilities and bond yields over the past 30 years is 3.17%. However, Dr. Avera concludes that a negative correlation exists between current bond yields and risk premiums and, due to that relationship, imputes a larger risk premium to reach an equity cost estimate of 10.7%.

It is important to understand at the outset that the annual cost rate differences between the allowed returns and utility bond yields are not necessarily reliable indicators of investor-required risk premiums. First, the allowed returns are simply averaged over all the available rate case decisions during a calendar year. That means that the capital market data that the regulatory body considered was drawn from a time prior to the decision rendered and the allowed return might not correlate with decision-time-specific macro-economic events. In some cases, that period of time between the hearing and the decision can be substantial.

Second, the relative risk of the utility for which the equity return was determined is not a factor in Dr. Avera's analysis. For example, the allowed return on equity for a near-bankrupt firm would simply be averaged in with the other returns allowed during a calendar year. Third, while the inclusion of an outlier may not be problematic in years in which there are many rate case decisions, that would not be the case in years in which the number of decisions is small, as in recent years. The source of Dr. Avera's data notes that "[a]s the number of equity return determinations has declined, the average authorized return now has less of a relationship to the return than the typical electric, gas, or telecommunications company has an opportunity to earn."

Q. YOU NOTED THAT DR. AVERA PLACES EMPHASIS ON A NEGATIVE CORRELATION BETWEEN INTEREST RATES AND RISK PREMIUMS IN REACHING HIS EQUITY COST ESTIMATE. PLEASE COMMENT ON THAT ISSUE.

A. Dr. Avera subtracts average bond yields for utilities from the equity returns allowed utility companies over the past 30 years. Then, through a regression analysis, the Company witness describes a relationship between bond yields and risk premiums and uses that relationship, with the current cost of debt to estimate the Company's cost of equity. Aside from the problems that exist generally with the data used in the analysis, noted above, there are additional problems with this particular approach. Further, those problems illustrate that Dr. Avera's adjustments to historically-derived risk premiums are not reliable for equity cost estimation purposes.

Although Dr. Avera's regression analysis shows a relatively strong correlation between risk premium and bond yields ($r^2 = 0.79$), that is not surprising because the resultant risk premium is a direct arithmetic function of the prevailing bond yield. A high correlation coefficient is not meaningful if the dependent and independent variables are said to be "auto-correlated."

If regression variables are auto-correlated, the differences between the actual values and the regression equation (the residuals) have a lagged correlation with their own past values (i.e., they are not independent of each other). Therefore, the regression equation will not necessarily serve as an accurate predictor of the relationship between the variables because the residual error will continue to increase over time. This can be especially problematic in time-series studies of the type included in Dr. Avera's risk premium analysis.

Dr. Avera does not offer the Commission any information regarding whether his data are auto-correlated. However, in the absence of any showing otherwise, it is reasonable to conclude that those data series are auto-correlated based on the inclusion of the risk premium as a variable. The risk premium is an arithmetic function of the bond yield, which is the other parameter in the regression.[25] Therefore, results of Dr. Avera's risk premium regression analysis may not be a reliable indicator of the cost of equity capital and should be given little weight by this Commission.

Q. ARE THERE OTHER STUDIES THAT EXAMINE THE RELATIONSHIP BETWEEN RISK PREMIUMS AND INTEREST RATE LEVELS?

A. Yes. Members of the Virginia Corporation Commission Staff published a study of that relationship in 1995.[26] That paper is interesting in that it shows that within certain shorter-term sub-periods an inverse relationship appears to exist, but over the entire 1980 through 1993 study period—as interest rates declined from the very high levels of the early 1980s—absolute risk premium levels fell. Moreover, this study was based on electric utility market return data and forward-looking equity cost rates rather than allowed equity cost rates.

The average risk premium between electric utility cost of equity and long-term Treasury bond yields averaged 3.21% over the 1980-1993 study period and the average T-bond yield was 9.77%. Given that the most recent six-week average T-Bond yield is 5.16%, the difference between the current T-Bond yield and that which existed, on average, during the study period (9.77%), is 4.61%. Multiplying that yield difference by the relationship found in the Virginia Commission Staff study produces a current risk premium of 4.91%

[25] One study of the correlation between risk premiums and bond yields recognizes that there is "severe positive autocorrelation" in the historical risk premium/bond yield data. (Harris, R., Marston, F., "The Market Risk Premium: Expectational Estimates Using Analyst's Forecasts," *Journal of Applied Finance*, 2001, pp. 6-16, footnote 7)

[26] Maddox, F., Pippert, D., and Sullivan, R., "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry," Financial Management, Vol. 24, No. 3, Autumn 1995, pp. 89-95.

(4.61% x 0.37 = 1.70% + 3.21% = 4.91%). That "adjusted" risk premium, added to the current T-Bond rate (5.16%) produces a cost of capital indication of 10.07% (5.16% + 4.91%).

Therefore, if one elects to believe such data are reliable (which I do not), there are studies of the relationship between interest rates and risk premiums in the literature which 1) show a declining trend in risk premiums over the 1980s and early 1990s, 2) are based on the cost of equity of electric utilities, not allowed returns anød 3) produce equity cost estimates which are substantially below those presented by Dr. Avera. Moreover, those results tend to corroborate the equity cost estimates I provide in this testimony.

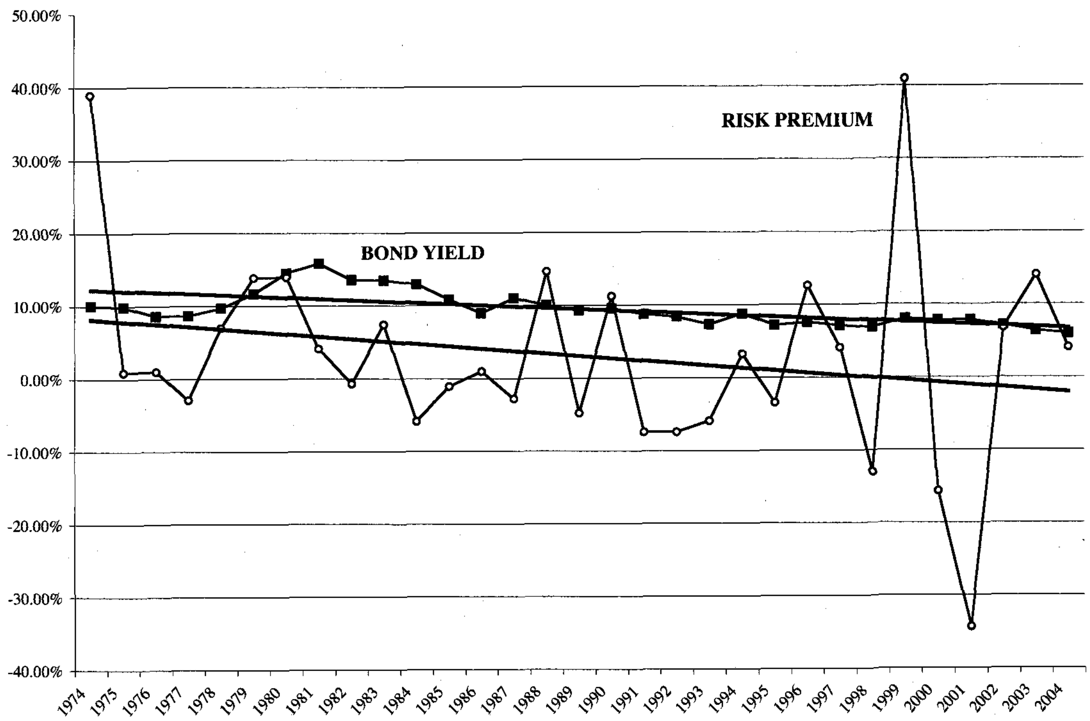
Q. IS THERE OTHER, MORE RECENT, EVIDENCE THAT COUNTERS DR. AVERA'S ASSUMPTION THAT EXPECTED RISK PREMIUMS VARY INVERSELY WITH INTEREST RATES?

A. Yes. In Section II of my testimony, I mentioned an on-going survey by professors at Duke University. Drs. John Graham and Campbell Harvey, in conjunction with *CFO Magazine* have, since 1999, polled corporate financial officers regarding their expectations regarding the expected market risk premium. In addition to the fact that found risk premiums to range from 2.5% to 4.5% (well below the historical risk premiums used by Dr. Avera), they also found that the expected risk premium varies directly with interest rates. That is, as interest rates decline, so too do expected risk premiums. Therefore, there is recently published evidence in the financial literature that directly counters Dr. Avera historical analysis that indicates risk premiums increase when interest rates decline.

In addition, Dr. Avera's other risk premium studies do not show a clear relationship between interest rates and risk premiums. As I noted in my discussion of Dr. Avera's realized rate of return analysis realized risk premiums have actually declined over the past thirty years as interest rates have fallen. In his "Authorized Rates of Return" Risk Premium analysis, shown on WEA-4, Dr. Avera studies the period 1974 through 2004. The Chart below shows the realized risk premium for utility investors from Dr. Avera's WEA-5 over the same time period.

CHART I

REALIZED RISK PREMIUM & INTEREST RATES



All data from Avera Direct, WEA-5.

The historical bond yields and the realized risk premiums are labeled in the Chart above, showing the data points for each year. Linear trend lines are also provided for each series. Chart I shows that the general trend in interest rates since 1974 (the beginning of Dr. Avera's study period) has been downward. It also shows that the trend in the realized risk premium of utility investors has also been downward over that same period. Moreover, the risk premium has declined at a more rapid rate than has the bond yield. These data, drawn from Dr. Avera's own testimony, tend to support the findings of Graham and Harvey, cited above. Namely, risk premiums decline when interest rates decline. These results, provided by Dr. Avera's own evidence, counters his claim that risk premiums rise when interest rates fall.

Q. PLEASE SUMMARIZE THE FLAWS IN DR. AVERA'S RISK PREMIUM COST OF EQUITY ANALYSES.

A. Dr. Avera's Risk Premium analyses of the cost of equity capital, 1) are based on studies which, in prior testimony, he has rejected as being unreliable, 2) ignore more recent studies which indicate much lower risk premium expectations by investors, 3) are based on a relationship between bond yields and risk premiums which he has not shown to be statistically reliable for unobservable equity risk premiums and which does not exist in readily observable risk premiums, and 4) are based on interest rate projections that are already incorporated into current yields and have been unreliable in the past. I do not believe Dr. Avera's risk premium analyses provide information that would be useful to this Commission in its task of determining the cost of equity capital for Arizona Public Service Company's electric utility operations.

Q. DOES THIS CONCLUDE YOUR DISCUSSION OF DR. AVERA'S COST OF CAPITAL ANALYSIS IN THIS PROCEEDING?

A. Yes, it does.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, MR. HILL?

A. Yes, it does.

APPENDIX A

EDUCATION AND EMPLOYMENT HISTORY
OF
STEPHEN G. HILL

EDUCATION

Auburn University - Auburn, Alabama - Bachelor of Science in Chemical Engineering (1971); Honors - member Tau Beta Pi national engineering honorary society, Dean's list, candidate for outstanding engineering graduate; Organizations - Engineering Council, American Institute of Chemical Engineers

Tulane University - New Orleans, Louisiana - Masters in Business Administration (1973); concentration: Finance; awarded scholarship; Organizations - member MBA curriculum committee, Vice-President of student body, academic affairs

Continuing Education - NARUC Regulatory Studies Program at Michigan State University

EMPLOYMENT

West Virginia Air Pollution Control Commission (1975)
Position: Engineer ; Responsibility: Overseeing the compliance of all chemical companies in the State with the pollution guidelines set forth in the Clean Air Act.

West Virginia Public Service Commission-Consumer Advocate (1982)
Position: Rate of Return Analyst ; Responsibility: All rate of return research and testimony promulgated by the Consumer Advocate; also, testimony on engineering issues, when necessary.

Hill Associates (1989)
Position: Principal; Responsibility: Expert testimony regarding financial and economic issue in regulated industries.

PUBLICATIONS

"The Market Risk Premium and the Proper Interpretation of Historical Data," Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, Volume I, pp. 245-255.
"Use of the Discounted Cash Flow Has Not Been Invalidated," Public Utilities Fortnightly, March 31, 1988, pp. 35-38.

MEMBERSHIPS

American Institute of Chemical Engineers; Society of Utility and Regulatory Financial Analysts (Certified Rate of Return Analyst, Member of the Board of Directors)

APPENDIX B

Q. PLEASE PROVIDE AN EXAMPLE WHICH DESCRIBES THE DETERMINANTS OF LONG-TERM SUSTAINABLE GROWTH.

A. Assume that a hypothetical regulated firm had a first period common equity or book value per share of \$10, the investor-expected return on that equity was 10% and the stated company policy was to pay out 60% of earnings in dividends. The first period earnings per share are expected to be \$1.00 (\$10/share book equity x 10% equity return) and the expected dividend is \$0.60. The amount of earnings not paid out to shareholders (\$0.40), the retained earnings, raises the book value of the equity to \$10.40 in the second period. The table below continues the hypothetical for a five year period and illustrates the underlying determinants of growth.

TABLE A.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	\$10.00	\$10.40	\$10.82	\$11.25	\$11.70	4.00%
EQUITY RETURN	10%	10%	10%	10%	10%	-
EARNINGS/SH.	\$1.00	\$1.040	\$1.082	\$1.125	\$1.170	4.00%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	-
DIVIDENDS/SH.	\$0.60	\$0.624	\$0.649	\$0.675	\$0.702	4.00%

We see that under steady-state conditions, the earnings, dividends and book value all grow at the same rate. Moreover, the key to this growth is the amount of earnings retained or reinvested in the firm and the return on that new portion of equity. If we let "b" equal the retention ratio of the firm (1 – the payout ratio) and let "r" equal the firm's expected return on equity, the DCF growth rate "g" (also referred to as the internal or sustainable growth rate) is equal to their product, or

$$g = br. \qquad \text{(i)}$$

Professor Myron Gordon, who developed the Discounted Cash Flow technique and first introduced it into the regulatory arena, has determined that Equation (i) embodies the underlying fundamentals of growth and, therefore, is a primary measure of growth to be used in the DCF model. Professor Gordon's research also indicates that analysts' growth rate projections are useful in estimating investors' expected sustainable growth.

I should note here that the above hypothetical does not allow for the existence of external sources of equity financing, i.e., sales of common stock. Stock financing will cause investors to expect additional growth if the company is expected to issue new shares at a market price that exceeds book value. The excess of market over book would inure to current shareholders, increasing their per share equity value. Therefore, if the company is expected to continue to issue stock at a price that exceeds book value, the shareholders would continue to expect their book value to increase and would add that growth expectation to that stemming from earnings retention or internal growth. Conversely, if a company were expected to issue new equity at a price below book value, that would have a negative effect on shareholder's current growth rate expectations. In such a situation, shareholders would perceive an overall growth rate less than that produced by internal sources (retained earnings). Finally, with little or no expected equity financing or a market-to-book ratio near unity, investors would expect the sustainable growth rate for the company to equal that derived from Equation (i), "g = br." Dr. Gordon[1] identifies the growth rate which includes both expected internal and external financing as:

$$g = br + vs, \tag{ii}$$

where,

g = DCF expected growth rate,
r = return on equity,
b = retention ratio,
v = fraction of new common stock sold that accrues to the current shareholder,
s = funds raised from the sale of stock

[1]Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp., 30–33.

as a fraction of existing equity.

Additionally,

$$v = 1 - BV/MP, \tag{iii}$$

where,

MP = market price,
BV = book value.

I have used Equation (iii) as the basis for my examination of the investor expected long-term growth rate (g) in this proceeding.

Q. IN YOUR PREVIOUS EXAMPLE, EARNINGS AND DIVIDENDS GREW AT THE SAME RATE (br) AS DID BOOK VALUE. WOULD THE GROWTH RATE IN EARNINGS OR DIVIDENDS, THEREFORE, BE SUITABLE FOR DETERMINING THE DCF GROWTH RATE ?

A. No, not necessarily. Rates of growth derived from earnings or dividends alone can be unreliable due to extraneous influences on those parameters such as changes in the expected rate of return on common equity or changes in the payout ratio. That is why it is necessary to examine the underlying determinants of growth through the use of a sustainable growth rate analysis.

If we take the hypothetical example previously stated and assume that, in year three, the expected return on equity rises to 15%, the resultant growth rate for earnings and dividends far exceeds that which the company could sustain indefinitely. The potential error in using those growth rates to estimate "g" is illustrated in the following table.

TABLE B.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.47	$12.157	5.00%
EQUITY RETURN	10%	10%	15%	15%	15%	10.67%
EARNINGS/SH.	$1.00	$1.040	$1.623	$1.720	$1.824	16.20%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	-
DIVIDENDS/SH.	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

What has happened is a shift in steady-state growth paths. For years one and two, the sustainable rate of growth (g=br) is 4.00%, just as in the previous hypothetical. Then, in the last three years, the sustainable growth rate increases to 6.00% (g=br = 0.4x15%). If the regulated firm were expected to continue to earn a 15% return on equity and retain 40% of its earnings, then a growth rate of 6.0% would be a reasonable estimate of the long-term sustainable growth rate. However, the compound annual growth rate for dividends and earnings exceeds 16% which is the result only of an increased equity return rather than the intrinsic ability of the firm to grow continuously at a 16% annual rate. Clearly, this type of estimate of future growth cannot be used with any reliability at all. In the case of the hypothetical, to utilize a 16% growth rate in a DCF model would be to expect the company's return on common equity to increase by 50% every five years into the indefinite future. This would be a ridiculous forecast for any regulated firm and underscores the importance of utilizing the underlying fundamentals of growth in the DCF model.

It can also be demonstrated that a change in our hypothetical regulated firm's payout ratio makes the past rate of growth in dividends an unreliable basis for predicting "g". If we assume our regulated firm consistently earns its expected equity return (10%) but in the third year, changes its payout ratio from 60% to 80% of earnings, the results are shown in the table below.

TABLE C.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.036	$11.26	3.01%
EQUITY RETURN	10%	10%	10%	10%	10%	-
EARNINGS/SH.	$1.00	$1.040	$1.082	$1.104	$1.126	3.01%
PAYOUT RATIO	0.60	0.60	0.80	0.80	0.80	7.46%
DIVIDENDS/SH.	$0.60	$0.624	$0.866	$0.833	$0.900	10.67%

What we see here is that, although the company has registered a high dividend growth rate (10.67%), it is, again, not at all representative of the growth that could be sustained indefinitely, as called for in the DCF model. In actuality, the sustainable growth rate has declined from 4.0% the first two years to only 2.0% (g=br = 0.2x10%) during the last three years due to the increased payout ratio. To utilize a 10% growth rate in a DCF analysis of this hypothetical regulated firm would 1) assume the payout ratio of the firm would continue to increase 33% every five years into the indefinite future, 2) lead to the highly implausible result that the firm intends to consistently pay out more in dividends than it earns and 3) grossly overstate the cost of equity capital.

APPENDIX C
SAMPLE COMPANY GROWTH RATE ANALYSES

ELECTRIC UTILITIES

CV – Central Vermont Public Service - CV's sustainable growth rate has averaged 2.28% over the most recent five year period (2001-2005), excluding the most recent year in which the results are not meaningful. Value Line expects CV's sustainable growth to rise above that historical growth rate level and reach 5% by the 2009-2011 period. CV's book value growth rate is expected to be 1% over the next five years. Book value increased at a 2.5% rate of growth over the past five years. CV's earnings per share are projected to increase at a 11.5% (Value Line) rate (Reuters and Zack's do not publish growth rate expectations for this company). Value Line's projected earnings growth is affected by CV's very low earnings in 2005, which forms the basis of the earnings growth calculation and is abnormally low. Looking at a longer-term period, from 2003 to 2010 (the mid-point of Value Line's projected period) the average earnings growth rate for CV would be about 3%. Over the past five years, CV's earnings growth was only 1% and its dividends increased at only a 0.5% rate. Investors can reasonably expect long-term sustainable growth rate in the future to be higher than the past but not as high as the company's current internal (b x r) growth projections; a growth rate of **4.0%** is reasonable for CV.

Regarding share growth, CV's shares outstanding increased at a 1.41% rate over the past five years. The growth the number of shares is projected by Value Line to decline dramatically through the 2009-11 period due to a stock buy-back program initiated in 2006 and financed by the sale of one of the company's unregulated subsidiaries. An expectation of share growth of **0%** for this company is reasonable.

FE – FirstEnergy Corp. - FE's sustainable growth rate averaged 3.15% over the five-year historical period, with negative results in 2003. Absent those recent results, the company's historical sustainable growth was about 4%. Value Line projects that the internal growth will increase through 2009-11, will bring sustainable growth to 5.6%. FE's book value, which increased at a 6% rate during the most recent five years, is expected to increase slightly to a 6.5% rate in the future. FE's earnings per share are projected to increase at 11.5% (Value Line) to 4.43% (Reuters), and 4.9% (Zack's) rates, indicating the variability of that growth rate measure. Value Line's projections are largely a function of it's three-year averaging technique, which includes FE's 2003 results in which it paid out more in dividends that it took in earnings, thereby depressing the base year average and causing the projected earnings to overstate long-term expectations. FE's dividends are expected to grow at a 5% rate, similar to other investor services' earnings growth expectations. Historically FE's earnings grew at a 0% rate, according to Value Line, and its dividends showed 2.5% growth over the past five years. The projected sustainable growth, earnings and book value growth rate data indicate that investors can expect the growth from FE in the future to be higher than that which has existed in the past. Investors can reasonably expect a sustainable growth rate of **5.50%** for FE.

Regarding share growth, FE's shares outstanding showed a 2.6% increase over the past five years. However, FE's growth rate in shares outstanding is expected to fall to a 0% rate of increase through 2009-11, and Value Line indicates a stock buy-back may be in the offing for this company. Those projections indicate that future share growth will be below past averages. An expectation of share growth of **0%** for this company is reasonable.

GMP – Green Mountain Power – GMP's sustainable growth rate has averaged 4.38% over the most recent five-year period, with a declining trend. Value Line expects GMP's sustainable growth to decline to approximately 3.3% by the 2009-2011 period. GMP's book value growth rate is expected to be 2.5% over the next five years, down from the 3% rate of growth experienced over the past five years, but below sustainable growth projections. Also, GMP's earnings per share are projected to increase at 3.5% according to Value Line. However, that investor service projects a 10% growth in dividends, following a 5% rate of growth for the previous five years. The 5-year historical compound rate of earnings growth for this company is 3.2%. The average projected dividend, earnings and book value growth for GMP is 5.67%. Largely due to Value Line's dividend growth projection, investors can reasonably expect a sustainable growth rate in the future of **5%** for GMP.

Regarding share growth, GMP's shares outstanding declined at approximately a 2% rate over the past five years. The number of shares is expected to grow at a 1% rate through 2009-11. An expectation of share growth of **0%** for this company is reasonable.

PGN- Progress Energy- PGN's sustainable growth rate has averaged 3.28% over the most recent five-year period. Value Line expects PGN's sustainable growth to decline to a growth rate level of 2% by the 2009-2011 period. PGN's book value growth rate is also expected to decline to 3% over the next five years, well below the 6.5% rate of growth experienced over the past five years, pointing to lower growth. Also, PGN's earnings per share are projected to increase at 1.5% (Value Line) to 2.87% (Reuters), to 3.6% (Zack's) rate—bracketing the indicated projected internal growth rate. Also, PGN's dividends are expected to grow at 2%, above earnings growth rate expectations and below historical dividend growth of 3%. Over the past five years PGN earnings grew at a 4.5% rate, according to Value Line's three-year base calculation methodology. Investors can reasonably expect a sustainable growth rate in the future of **3.0%** for PGN.

Regarding share growth, PGN's shares outstanding increased at approximately a 3.6% rate over the past five years. The number of shares outstanding in 2009-2011 is expected to show about a 0.7% increase from 2004 levels. That increase will leave the total number of shares at a lower level than existed in 2000. An expectation of share growth of **1.5%** for this company is reasonable.

AEE – Ameren Corp. - AEE's sustainable growth rate has averaged 1.79% over the most recent five year period (2001-2005), with a declining trend. Value Line expects AEE's sustainable growth to improve a bit over recent low growth rate levels and reach 2.2% by the 2009-2011 period. AEE's book value growth rate also shows a decline in the future, and is expected to be 3% over the next five years, below the 5% rate of growth experienced over the past five years, but above internal growth projections. Also, AEE's earnings per share are projected to increase at a 1.5% (Value Line) rate. Reuters and Zacks project 5.2% and 6% earnings growth for AEE, respectively. AEE's dividends are expected to show no growth over the next five years, after growing at a 0% rate the previous five years, according to Value Line. Over the past five years, AEE's earnings growth was 0.5%. Based on projected earnings and book value growth, investors can reasonably expect long-term sustainable growth rate in the future to be higher than the internal growth projections published by Value Line; a growth rate of **3.75%** is reasonable for AEE.

Regarding share growth, AEE's shares outstanding increased at a 10.35% rate over the past five years due to a series of equity issuances. The growth the number of shares is projected by Value Line to increase at about a 1.1% rate between 2004 and the 2009-11 period. An expectation of share growth of **2.5%** for this company is reasonable.

CNL – Cleco Corp. - CNL's sustainable growth rate averaged 4.56% for the five-year period, with the results in the most recent years below that average. Value Line expects sustainable growth to continue at about a 3.9% level through the 2009-11 period. CNL's book value growth is expected to increase at an 8% rate, well above the historical level of 4%, due to the building of a new power plant. CNL's earnings per share is projected to show 4.5% growth over the next five years, and its dividends are expected to show 2% growth, according to Value Line (Reuters & Zacks project 8% earnings growth). Historically CNL's earnings increased at a 1% rate and its dividends increased at a 2% rate of growth, according to Value Line. These data indicate that future growth will be above prior growth rate averages. Investors can reasonably expect sustainable growth from CNL to be below past averages, a sustainable internal growth rate of **4.75%** is a reasonable expectation for this company.

Regarding share growth, CNL's shares outstanding grew at approximately a 2.7% rate over the past five years. The growth in the number of shares is expected by Value Line to be 6.3% through 2009-11. An expectation of share growth of **4%** for this company is reasonable.

DPL – DPL, Inc.- DPL's sustainable growth rate has averaged 4.40% over the most recent five-year period. Value Line expects DPL's sustainable growth to increase to approximately 6.5% by the 2009-2011 period. DPL's book value growth rate is expected to be 1.5% over the next five years, up substantially from the -1% rate of growth experienced over the past five years, but well below sustainable growth projections. Also, DPL's earnings per share are projected to increase at a rate of from 5.5% (Value Line), to 7.5% (Reuters), to 7% (Zack's). Over the past five years, DPL's earnings growth was -1% according to Value Line. Historically, dividends grew at only a 0.5% rate, and Value Line expects that rate to increase to 3.5% over the next five years. Investors can reasonably expect a higher sustainable growth over the long term — **6.5%** for DPL is reasonable.

Regarding share growth, DPL's shares outstanding increased at a 0.2% rate over the past five years. The number of shares is expected to decline at a 1.2% rate through 2009-11. An expectation of share growth of **0%** for this company is reasonable.

EDE – Empire District Electric - EDE's sustainable internal growth rate averaged –2% over the five-year historical period, with several negative growth years. Value Line projects EDE's sustainable growth to rise to a level of only 1.4% through 2009-11—a substantial improvement over historical results. EDE's book value growth rate is expected to continue in the future at 2%, the same as the historical level of 2%. However, EDE's earnings per share are projected to increase at 6.5% to according to Value Line, while the analysts' surveyed by Reuters project earnings growth at 2.5%, a wide differential. EDE's dividends are expected to remain at a constant level over the next five years (i.e., showing 0% growth), and moderating long-term growth expectations. Sustainable growth has been relatively inconsistent for this company, historically and is expected to trend upward in the future. Dividend growth has been non-existent, but the company has continued to pay its dividend. Also, Value Line's earnings growth projection is skewed upward by their inclusion of the company's poor 2004 earnings in is "base" three-year period. From 2003 through the mid-point of the 2009-2011 period, Value Line's projected earnings per share indicate a 2.5% growth rate. Investors can reasonably expect a sustainable growth rate of **3.0%** from EDE.

Regarding share growth, EDE's shares outstanding grew at about a 7% rate over the past five years, due primarily to a large equity issuance in 2002. The level of share growth is expected by Value Line to decline somewhat to 4.8% through 2009-11. An expectation of share growth of **5%** for this company is reasonable.

ETR – Entergy Corp. - ETR's internal sustainable growth rate has averaged 5.94% over the most recent five year period (2001-2005). Sustainable growth is expected to decline to about 5% by the 2009-2011 period. Also, ETR's book value growth rate is expected to be 5% over the next five years—a slight increase from the 4.5% rate of growth experienced over the past five years—pointing to relatively stable growth expectations for the future. ETR's earnings per share are projected to increase at a rate of from 5% (Value Line) to 7.5% (Zack's) to 7.17% (Reuters). ETR's dividends are expected to grow at a high 7% growth rate, supporting higher sustainable growth expectations. Over the past five years, ETR's earnings grew at a 10% rate according to Value Line (8% on a compound growth basis) while its dividends showed 7.5% growth. These data indicate that investors can reasonably expect a sustainable growth rate in the future below past averages, however earnings growth projections are above historical sustainable growth. Therefore, **6.0%** is a reasonable long-term growth expectation for ETR.

Regarding share growth, ETR's shares outstanding grew at a –1.5% rate over the past five years. The number of shares outstanding is projected by Value Line to continue to increase at approximately a 0.8% rate through 2009-11. An expectation of share growth of **0%** for this company is reasonable.

HE – Hawaiian Electric - HE's sustainable growth rate has averaged 1.97% over the most recent five year period (2001-2005), with lower growth in the most recent year, indicating a decreasing trend. However, Value Line expects HE's sustainable growth to increase from that historical growth rate level to reach 3% by the 2009-2011 period. Also, HE's book value growth rate is expected to be 2.5% over the next five years, down from the 3% rate of growth experienced over the past five years. HE's earnings per share are projected to increase at a 3% (Value Line) to 5.2% (Zack's) to 2.9% (Reuters) rate. The company's dividends are expected to show 0% growth over the next five years. Over the past five years, HE's earnings grew at a 1% rate while its dividends showed no increase. Investors can reasonably expect a sustainable growth rate in the future of **3.5%** for HE.

Regarding share growth, HE's shares outstanding grew at a 3.27% rate over the past five years. The number of shares is projected by Value Line to show a 0.25% rate of increase through the 2009-11 period. An expectation of share growth of **1%** for this company is reasonable.

PNM Resources – PNM - PNM's sustainable growth rate has averaged 5.37% over the most recent five year period with a declining trend. Value Line expects PNM's sustainable growth to fall below that historical average growth rate level to about 3.5% by the 2009-2011 period. PNM's book value growth rate is expected to be 4% over the next five years, similar to the 4.5% rate of growth experienced over the past five years. Those data indicate stable growth. Also, PNM's earnings per share are projected to increase at a 5.5% (Value Line) to 8.3% (Zacks) to 11.45% (Reuters) rate. Its dividends are expected to grow at 8.5%, increasing long-term growth rate expectations. Over the past five years, PNM's earnings growth was -1% while its dividends increased at a 5% rate. Investors can reasonably expect a sustainable growth rate in the future of **5.75%** for PNM.

Regarding share growth, PNM's shares outstanding increased at a 4% rate over the past five years. The number of shares outstanding in 2009-2011 is expected to increase at about a 1.5% rate from 2005 levels. An expectation of share growth of **2%** for this company is reasonable.

Pinnacle West – PNW - PNW's sustainable growth rate has averaged 3.22% over the most recent five-year period with a downward trend. Value Line expects PNW's sustainable growth to fall below that historical average growth rate level to 2.84% by the 2009-2011 period. PNW's book value growth rate is expected to be 3.5% over the next five years, just below to the 4% rate of growth experienced over the past five years, indicating relatively stable growth expectations for this firm. PNW's earnings per share is projected to increase at a 6% (Value Line), to 7.6% (Reuters), to 6.8% (Zack's) rate—all well above the projected internal growth rate. PNW's dividends are expected to grow at a 5% rate, supporting higher long-term growth rate expectations. Over the past five years, PNW's earnings growth was –4.5% while its dividends increased at a 6.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **5.0%** for PNW.

Regarding share growth, PNW's shares outstanding increased at approximately a 4% rate over the past five years due to a share issuance in 2002. The number of shares outstanding in 2009-2011 is expected to show a 0% increase from 2005 levels. An expectation of share growth of **1%** for this company is reasonable.

UNS – Unisource Energy - UNS's sustainable growth rate has averaged 5.29% over the most recent five year period. Value Line expects UNS's sustainable growth to decline below that historical growth rate level, to about 3.5%, by the 2009-2011 period. UNS's book value growth rate is expected to be 5% over the next five years, below the very high 12% rate of growth experienced over the past five years UNS's earnings per share are projected to increase at a rate of 7% (Value Line). Zack's and Reuters do not report projected earnings growth for this company. Its dividends are expected to grow more rapidly, at a 9.5% rate—catching up from an historical growth rate of 0%. Over the past five years, UNS's earnings growth was 5%. Investors can reasonably expect a sustainable growth rate in the future to be similar to that of the past and **5.25%** is reasonable for UNS.

Regarding share growth, UNS's shares outstanding increased at approximately a 1% rate over the past five years. That rate of increase is expected to decline in the future to a 1.2% rate through 2009-2011. An expectation of share growth of **1%** for this company is reasonable.

APPENDIX D

CORROBORATIVE EQUITY CAPITAL COST ESTIMATION METHODS

CAPITAL ASSET PRICING MODEL

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL (CAPM) YOU USED TO ARRIVE AT AN ESTIMATE FOR THE COST RATE OF THE COMPANY'S EQUITY CAPITAL.

A. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (systematic) risk of a security. Systematic risk refers to the risk associated with movements in the macro-economy (the economic "system") and, thus, cannot be eliminated through diversification by holding a portfolio of securities. The beta coefficient (β) is a statistical measure that attempts to quantify the non-diversifiable risk of the return on a particular security against the returns inherent in general stock market fluctuations. The formula is expressed as follows:

$$k = r_f + \beta(r_m - r_f), \qquad \text{(i)}$$

where "k" is the cost of equity capital of an individual security, "r_f" is the risk-free rate of return, "β" is the beta coefficient, "r_m" is the average market return and "$r_m - r_f$" is the market risk premium. The CAPM is used in my analysis, not as a primary cost of equity analysis, but as a check of the DCF cost of equity estimate. Although I believe the CAPM can be useful in testing the reasonableness of a cost of capital estimate, certain theoretical shortcomings of this model (when applied in cost of capital analysis) reduce its usefulness.

Q. CAN YOU EXPLAIN WHY YOU APPLY THE CAPM ANALYSIS WITH CAUTION?

A. Yes. The reasons why the CAPM should be used in cost of capital analysis with caution are set out below. It is important to understand that my caution with regard to the use of the CAPM in a cost of equity capital analysis does not indicate that the model is not a useful description of the capital markets. Rather, it recognizes that in the practical application of the CAPM to cost of capital analysis there are problems that can cause the results of that type of analysis to be less reliable than other, more widely accepted models such as the DCF.

The CAPM was originally designed as a point-in-time tool for selecting stock portfolios that matched a particular investor's risk/return preference. Its use in rate of return analysis to estimate multi-period return expectations for one stock or one type of stock, rather than a diversified portfolio of stocks, takes the model out of the context for which it was intended. Also, questions regarding the fundamental applicability of the CAPM theory and the accuracy of beta have arisen recently in the financial literature.

Over the past few years there has been much comment in the financial literature over the strength of the assumptions that underlie the CAPM and the inability to substantiate those assumptions through empirical analysis. Also, there are problems with the key CAPM risk measure that indicate that the CAPM analysis is not a reliable primary indicator of equity capital costs.

Cost of capital analysis is a decidedly forward-looking, or *ex-ante*, concept. Beta is not. The measurement of beta is derived with historical, or *ex-post*, information. Therefore, the beta of a particular company, because it is usually derived with five years of historical data, is slow to change to current (i.e., forward-looking) conditions, and some price abnormality that may have happened four years ago could substantially affect beta while, currently, being of little actual concern to investors. Moreover, this same shortcoming which assumes that past results mirror investor expectations for the future plagues the market risk premium in an ex-post, or historically-oriented CAPM.

Also, an important study performed for the Center for Research in Security Prices at the University of Chicago Graduate School of Business shows that the assumed linear relationship between beta, risk and return (i.e., beta varies directly with risk and return) simply does not appear to exist in the marketplace. As Value Line reported in its Industry Review published in March of 1992:

> Two of the most prestigious researchers in the financial community, Professors Eugene F. Fama and Kenneth R. French from the University of Chicago have challenged the traditional relationship between Beta and return in a recent paper published by the Center for Research in Security Prices. In this study, the duo traced the performance of thousands of stocks over 50 years, but found no statistical support for the hypothesis that the relationship between volatility and return is significantly different from random. (Value Line Industry Review, March 13, 1992, p. 1-8.)

Fama and French have continued their investigation of the CAPM since their 1992 article and have postulated that a more accurate CAPM would use two additional risk measures in addition to beta. However, it is important to note that while those authors tout the superiority of their three-factor CAPM to the single-beta CAPM on theoretical grounds, they recognize that there are significant problems with any type of asset pricing model when it comes to using the model to estimate the cost of equity capital. Most recently, Fama and French noted regarding the CAPM:

> "The attraction of the CAPM is that is offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor—poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model….In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid." (Fama, E., French, K., "The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004, pp. 25-46)

While the recently published conclusions as to the imprecision of equity cost estimates produced by CAPM-type models does not negate the risk/return basis of asset pricing, they do call for more accurate measures with which asset returns can be more reliably indexed. However, unless and until such indices are published and widely accepted in the marketplace, CAPM cost of equity capital estimates should be relegated to a supporting role or informational status. Therefore, I use the CAPM for informational purposes and do not rely on that methodology as a primary equity capital cost estimation technique.

Q. WHAT VALUE HAVE YOU CHOSEN FOR A RISK-FREE RATE OF RETURN IN YOUR CAPM ANALYSIS?

A. As the CAPM is designed, the risk-free rate is that rate of return investors can realize with certainty. The nearest analog in the investment spectrum is the 13-week U. S. Treasury Bill. However, T-Bills can be heavily influenced by Federal Reserve policy, as they have been over the past three years. While longer-term Treasury bonds have equivalent default risk to T-Bills, those longer-term government securities carry maturity risk that the T-Bills do not have. When investors tie up their money for longer periods of time, as they do when purchasing a long-term Treasury, they must be compensated for future investment opportunities forgone as well as the potential for future changes in inflation. Investors are compensated for this increased investment risk by receiving a higher yield on T-Bonds. However, when T-Bills and T-Bonds exhibit a "normal" (historical average) spread of about 1.5% to 2%, the results of a CAPM analysis that matches a higher market risk premium with lower T-Bill yields or a lower market risk premium with higher T-Bond yields, are very similar.

As I noted in my previous discussion of the macro-economy, the Fed has acted vigorously during the past year or so to raise short-term interest rates. Over the most recent six-week period, T-Bills have produced an average yield of 4.84% and Treasury Bonds have yielded 5.16% (data from Value Line *Selection & Opinion*, six most recent weekly editions[1]). Those data indicate that, currently, there is an abnormally low yield differential between long- and short-term Treasury securities.

Q. DO YOU BELIEVE THE USE OF A LONG-TERM TREASURY BOND RATE IS APPROPRIATE IN THE CAPM?

A. In the current economic environment, the use of a long-term Treasury bond produces a more accurate estimate of investors' cost of equity. Although the selection of a long- or short-term Treasury security as the risk free rate of return to be used in the CAPM is one of the areas of contention in applying the model in cost of capital analysis, the use of a normalized short-term T-Bill rate is the more prevalent in the literature. However, as noted above the T-Bill yield can be influenced by Federal Reserve policy, and, can produce inaccurate indications of the cost of equity, especially if the yield differential between T-Bonds and T-Bills is different from long-term averages as they are now.

For example, in 2004 when the Fed had pushed T-Bill rates below 2% and the yield differential between T-Bonds and T-Bills was unusually large, the results of a T-Bill-based CAPM for utilities were below bond yields and were not reliable. Recently, with the Fed pushing up short-term T-Bill yields resulting through credit tightening, combined with stable long-term yields, the yield differential between T-Bonds and T-Bills has shrunk to about 0.3%, which is well below long-term averages of about 1.8% to 2.1%. Therefore, the short-term CAPM will overstate the cost of equity. For purposes of analysis in this proceeding I will rely on the long-term Treasury bond yields for the risk-free rate in the CAPM. Also, along with those measures of the risk-free rate I use the corresponding measures of market risk premiums.

Q. WHAT HAVE YOU CHOSEN AS THE MARKET RISK PREMIUM FOR THE CAPM ANALYSIS?

A. In their 2006 edition of Stocks, Bonds, Bills and Inflation, R.G. Ibbotson Associates indicates that the average market risk premium between stocks and T-Bills over the

[1] Current T-Bill yield, six-week average yield from Value Line Selection & Opinion (5/26/06-6/30/06).

1926–2005 time period is 6.5% (based on an arithmetic average), and 4.9% (based on a geometric average). For short-term Treasuries, the market risk premiums are 8.6% (based on an arithmetic average) and 6.7% (based on a geometric average). I have used these values to estimate the market risk premium in the CAPM analysis. The geometric mean is based on compound returns over time and the arithmetic mean is based on the average of single-period returns.

It is also important to note that, as I point out in Section I of my testimony, recent research in the field of financial economics has shown that the market risk premium data published by Ibbotson Associates—the earned return differentials that existed in the U.S. between 1926 and 2003—overstates investor-expected market risk premiums. The most recent research indicates that the return investors require over the risk-free rate ranges from 2.5% to 4.5% as opposed to the 4.9% to 6.5% estimate published by Ibbotson. Also Ibbotson, himself, has published a recent paper that indicates the forward-looking risk premium expectation ranges between 4% and 6%.[2] Therefore, the upper end of the CAPM cost of equity estimates, based on the historical Ibbotson data, should be considered to be higher than the current cost of common equity capital.

Q. IF THE IBBOTSON HISTORICAL DATA OVERSTATE THE EXPECTED MARKET RISK PREMIUM, WHY DO YOU USE THOSE DATA IN YOUR CAPM ESTIMATE OF THE COST OF COMMON EQUITY CAPITAL?

A. I continue to utilize the historical Ibbotson data in my CAPM analysis in order to be consistent with the manner in which I have traditionally used those data. I have been testifying on the subject of the cost of equity capital for more than twenty years and have consistently used the Ibbotson historical data in my CAPM analyses, and choose not to deviate from that practice at this time. However, the new research on the market risk premium (including a paper from Ibbotson, himself) indicates that the market risk premium expected by investors is considerably lower than the risk premium contained in the Ibbotson historical data. While that information does not cause me to change my

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[2] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

long-standing CAPM methodology of relying on the Ibbotson historical risk premium data, the current research on the topic of the market risk premium is important, deserves consideration and causes me to put considerably less weight on the higher end of the CAPM estimates.

Q. WHAT VALUES HAVE YOU CHOSEN FOR THE BETA COEFFICIENTS IN THE CAPM ANALYSIS?

A. Value Line reports beta coefficients for all the stocks it follows. Value Line's beta is derived from a regression analysis between weekly percentage changes in the market price of a stock and weekly percentage changes in the New York Stock Exchange Composite Index over a period of five years. The average beta coefficient of the sample of electric companies is 0.83.

Q. WHAT IS YOUR RECOMMENDED COST OF EQUITY CAPITAL FOR THE SAMPLE OF GAS AND ELECTRIC COMPANIES USING THE CAPITAL ASSET PRICING MODEL ANALYSIS?

A. Schedule 8 shows that the average Value Line beta coefficient for the group of electric companies under study, rounded to two decimal places, is 0.83. The overall arithmetic average market risk premium of 6.5% would, upon the adoption of a 0.83 beta, become a sample group premium of 5.40% (0.83 x 6.5%). That non-specific risk premium added to the risk-free T-Bond rate of 5.16%, previously derived, yields a common equity cost rate estimate of 10.56%. Using the geometric market risk premium of 4.90% with the current T-Bond yield produces a CAPM estimate of 9.23%.

Also, if T-Bill rates were at normal historical levels (approximately 2% below long-term rates, or, in this instance 3.40%), a CAPM based on T-Bill yields as a measure of the risk premium would range from 9.0% to 10.0%. A normalized T-Bill yield of 3.40% added to the sample-average beta coefficient (0.83), multiplied by geometric and arithmetic historic return differentials between the market and T-Bills (6.70% and 8.60%, respectively), would produce a CAPM estimate of 8.96% to 10.54%.

As noted in the discussion above, that upper-end estimate of any CAPM estimate based on the Ibbotson historical data is likely to exceed the current cost of equity capital. However, those CAPM results bracket the DCF results derived previously, supporting the reasonableness of those results.

MODIFIED EARNINGS-PRICE RATIO ANALYSIS

Q. PLEASE DESCRIBE THE MODIFIED EARNINGS-PRICE RATIO (MEPR) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL.

A. The earnings-price ratio is calculated simply as the expected earnings per share divided by the current market price. In cost of capital analysis, the earnings-price ratio (which is one portion of this analysis) can be useful in a corroborative sense, since it can be a good indicator of the proper range of equity costs when the market price of a stock is near its book value. When the market price of a stock is *above* its book value, the earnings-price ratio *understates* the cost of equity capital. Schedule 9 contains mathematical proof for this concept. The opposite is also true, i.e.; the earnings-price ratio *overstates* the cost of equity capital when the market price of a stock is *below* book value.

Under current market conditions, the utilities under study have an average market-to-book ratio of 1.69 and, therefore, the average earnings-price ratio alone would understate the cost of equity for the sample groups. However, I do not use the earnings-price ratio alone as an indicator of equity capital cost rates. Because of the relationship among the earnings-price ratio, the market-to-book ratio and the investor-expected return on equity described in Schedule 9, I have modified the standard earnings-price ratio analysis by including expected returns on equity for the companies under study. It is that modified analysis that I will use to assist in estimating an appropriate range of equity capital costs in this proceeding.

Q. PLEASE EXPLAIN THE RELATIONSHIP AMONG THE EARNINGS-PRICE RATIO, THE EXPECTED RETURN ON EQUITY, AND THE MARKET-TO-BOOK

RATIO.

A. When the expected return (ROE) approximates the cost of equity, the market price of the utility approximates its book value and the earnings-price ratio provides an unbiased estimate of the cost of equity. When the investor-expected return on equity for a utility (ROE) exceeds the investor-required return (the cost of equity capital), the market price of the firm will tend to exceed its book value. As explained above, when the market price exceeds book value, the earnings-price ratio understates the cost of equity capital. Therefore, when the expected equity return (ROE) exceeds the cost of equity capital, the earnings-price ratio will understate that cost rate.

When market-to-book ratios are above one, the expected equity return exceeds and the earnings-price ratio understates the cost of equity capital. When market-to-book ratios are below one, the expected equity return understates and the earnings-price ratio exceeds the cost of equity capital. Further, as market-to-book ratios approach unity, the expected return and the earnings price ratio approach the cost of equity capital. Therefore, the average of the expected book return and the earnings price ratio provides a reasonable estimate of the cost of equity capital.

These relationships represent general rather than precisely quantifiable tendencies but are useful in corroborating other cost of capital methodologies. The Federal Energy Regulatory Commission, in its generic rate of return hearings, found this technique useful and indicated that under the circumstances of market-to-book ratios exceeding unity, the cost of equity is bounded above by the expected equity return and below by the earnings-price ratio (e.g., 50 Fed Reg, 1985, p. 21822; 51 Fed Reg, 1986, pp. 361, 362; 37 FERC ¶ 61,287). The mid-point of these two parameters, therefore, produces an estimate of the cost of equity capital which, when market-to-book ratios are different from unity, is far more accurate than the earnings-price ratio alone.

Q. WHAT ARE THE RESULTS OF YOUR EARNINGS-PRICE RATIO ANALYSIS OF THE COST OF EQUITY FOR THE SAMPLE GROUP?

A. Schedule 10 shows the Reuters projected 2007 per share earnings for each of the firms in the sample groups. Recent average market prices (the same market prices used in my DCF analysis), Value Line's projected return on equity for 2007 and 2009-2011 for each of the companies are also shown.

The average earnings-price ratio for the electric sample group, 7.23%, is below the cost of equity for those companies due to the fact that their average market-to-book ratio is currently above unity (average electric utility M/B = 1.69). The sample electric companies' 2007 expected book equity return averages 11.04%. For the electric sample group, then, the mid-point of the earnings-price ratio and the current equity return is 9.13%.

Schedule 10 also shows that the average expected book equity return for the electric utilities over the next three- to five-year period declines slightly to 10.35%. The midpoint of these two boundaries of equity capital cost for the whole group, i.e., the long-term projected return on book equity (10.35%) and the current earnings-price ratio (7.23%) is 8.79%. That longer-term analysis provides another forward-looking estimate of the equity capital cost rate of electric utility firms. The results of this MEPR analysis indicate that the DCF equity cost estimate previously derived may be overstated (i.e., too high).

MARKET-TO-BOOK RATIO ANALYSIS

Q. PLEASE DESCRIBE YOUR MARKET-TO-BOOK (MTB) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL FOR THE SAMPLE GROUPS.

A. This technique of analysis is a derivative of the DCF model that attempts to adjust the capital cost derived with regard to inequalities that might exist in the market-to-book ratio. This method is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method. However, the MTB analysis is useful in a corroborative sense. The MTB seeks to determine the cost of equity using market-determined parameters in a format different from that employed in the DCF analysis. In the DCF analysis, the available data is "smoothed" to identify investors' long-term sustainable expectations. The MTB analysis, while based on the DCF theory, relies instead on point-in-time data projected one year and five years into the future and, thus, offers a practical corroborative check on the traditional DCF. The MTB formula is derived as follows:

Solving for "P" from Equation (1), the standard DCF model, we have

$$P = D/(k\text{-}g). \qquad \text{(ii)}$$

But the dividend (D) is equal to the earnings (E) times the earnings payout ratio, or one minus the retention ratio (b), or

$$D = E(1\text{-}b). \qquad \text{(iii)}$$

Substituting Equation (iii) into Equation (ii), we have

$$P = \frac{E(1\text{-}b)}{k\text{-}g}. \qquad \text{(iv)}$$

The earnings (E) are equal to the return on equity (r) times the book value of that equity (B). Making that substitution into Equation (iv), we have

$$P = \frac{rB(1\text{-}b)}{k\text{-}g}. \qquad \text{(v)}$$

Dividing both sides of Equation (v) by the book value (B) and noting from Equation (iii) in Appendix B that g = br+sv,

$$\frac{P}{B} = \frac{r(1\text{-}b)}{k\text{-}br\text{-}sv}. \qquad \text{(vi)}$$

Finally, solving Equation (vi) for the cost of equity capital (k) yields the MTB formula:

$$k = \frac{r(1-b)}{P/B} + br + sv. \qquad \text{(vii)}$$

Equation (vii) indicates that the cost of equity capital equals the expected return on equity multiplied by the payout ratio, divided by the market-to-book ratio plus growth. Schedule 11 shows the results of applying Equation (vii) to the defined parameters for the electric utility firms in the comparable sample. For the electric utility sample group, page 1 of Schedule 11 utilizes current year (2006) data for the MTB analysis while page 2 utilizes Value Line's 2009-2011 projections.

The MTB cost of equity for the sample of electric utility firms, recognizing a current average market-to-book ratio of 1.69 is 9.31% using the current year data and 9.38% using projected three- to five-year data. Those point-in-time estimates are slightly below, but tend to confirm my DCF equity cost estimate.

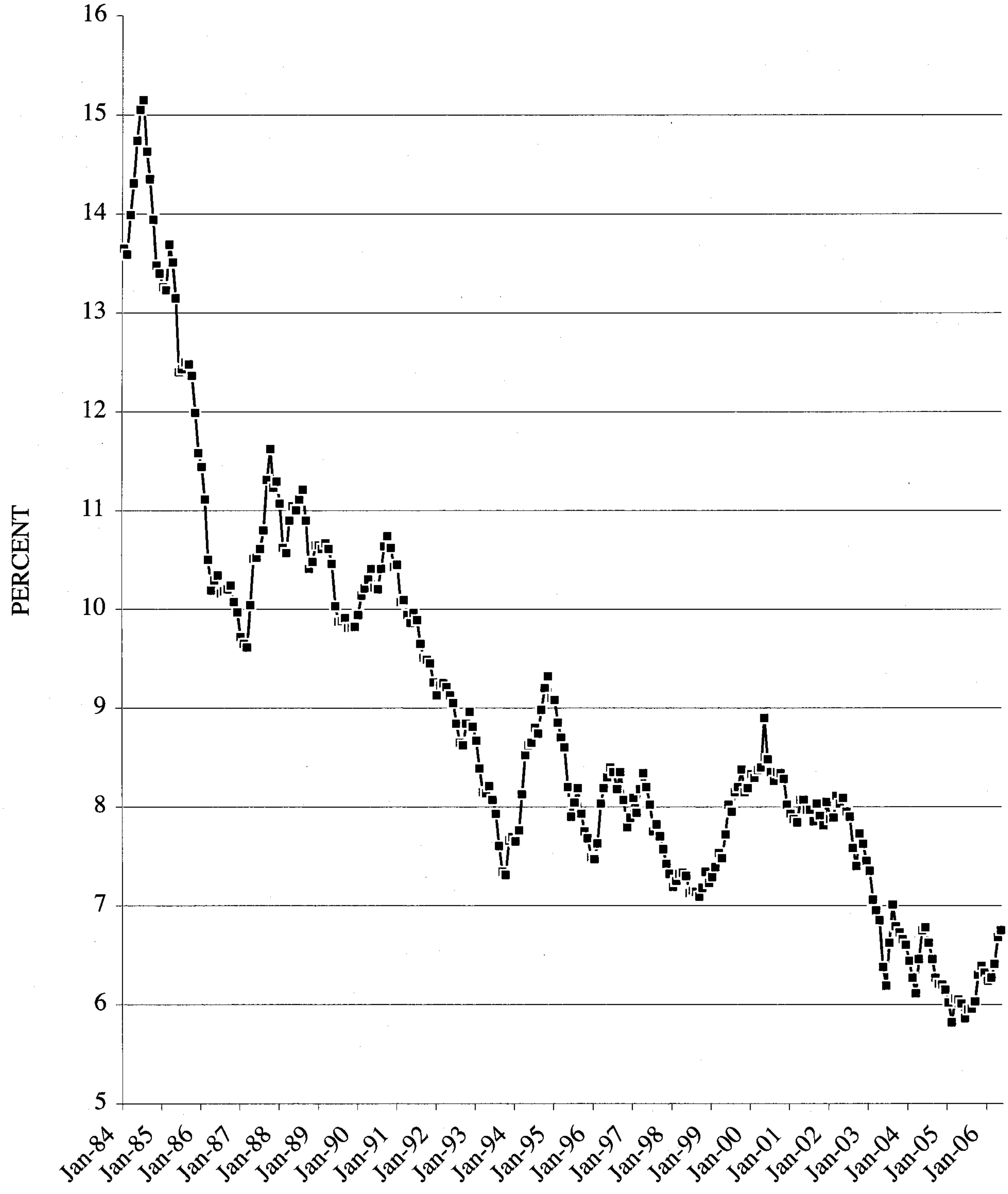
Q. DOES THIS CONCLUDE YOUR DISCUSSION OF YOUR CORROBORATIVE EQUITY COST ESTIMATION ANALYSES?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY

MOODY'S BAA BOND YIELDS

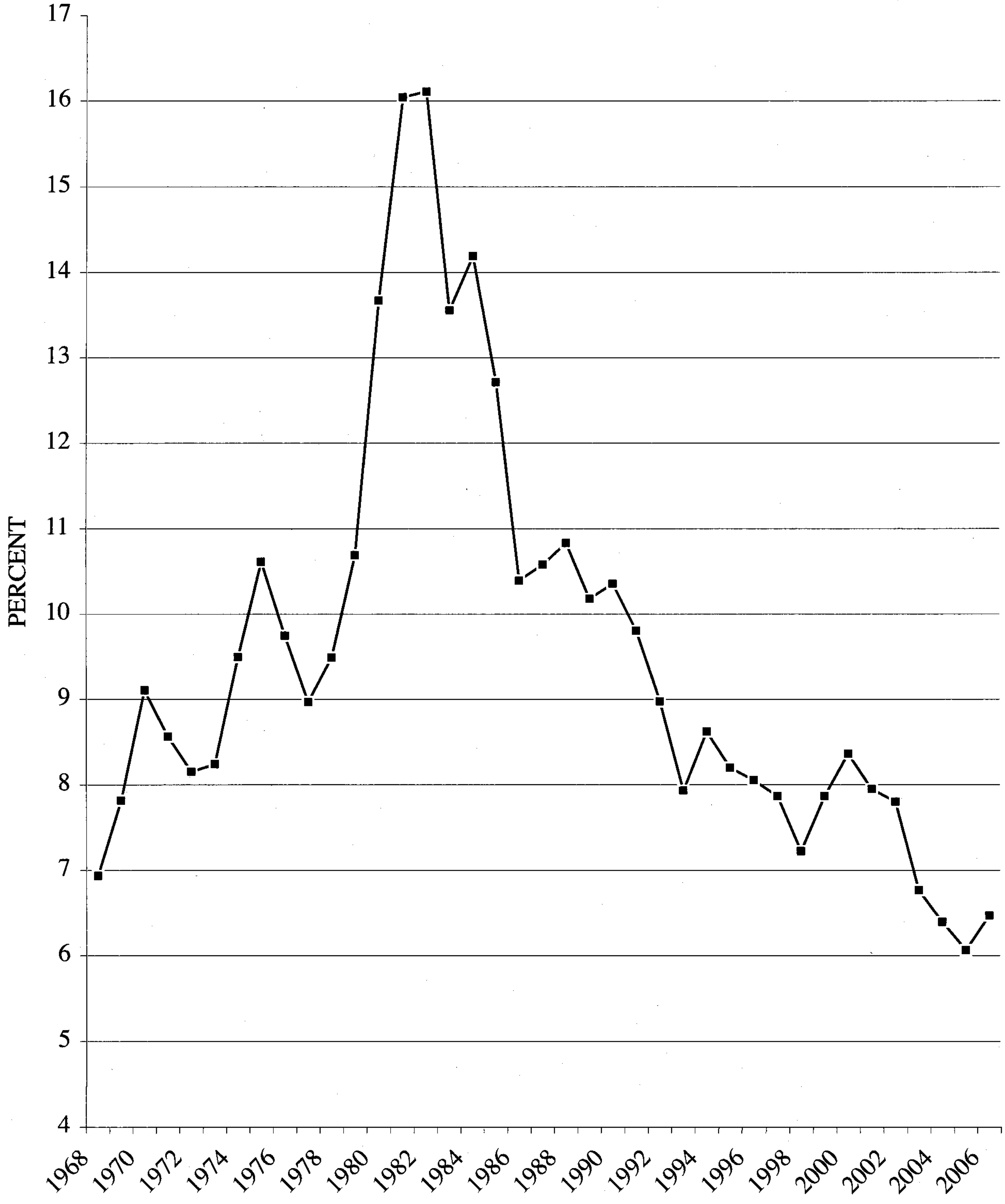
1984-2006



Data from Federal Reserve Release H.15.

ARIZONA PUBLIC SERVICE COMPANY

MOODY'S BAA BOND YIELDS
1968-2005



Data from Federal Reserve Release H.15.

ARIZONA PUBLIC SERVICE COMPANY
HISTORICAL CAPITAL STRUCTURE

AMOUNT (000,000)

Type of Capital	Mar-05	Jun-05	Sep-05	Dec-05	Mar-06	**Average**
Common Equity	$2,281.7	$2,428.4	$3,017.1	$2,985.2	$2,999	**$2,742**
Long-term Debt	$2,618.1	$2,617.9	$2,565.5	$2,565.3	$2,565	**$2,586**
Short-term Debt	$0.0	$0.0	$0.0	$0.0	$0	**$0**
TOTAL	$4,899.8	$5,046.3	$5,582.6	$5,550.5	$5,564	**$5,329**

PERCENTAGE INCLUDING SHORT-TERM DEBT

Type of Capital	Mar-05	Jun-05	Sep-05	Dec-05	Mar-06	**5 Quarter Average**
Common Equity	46.57%	48.12%	54.04%	53.78%	53.90%	**51.46%**
Long-term Debt	53.43%	51.88%	45.96%	46.22%	46.10%	**48.54%**
Short-term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	**48.54%**

Data from Company response to RUCO-3-1 and First Quarter 2006 S.E.C. Form 10-Q.

ARIZONA PUBLIC SERVICE COMPANY
ANNUAL COST OF RECAPITALIZATION

RATE CASE CAPITAL STRUCTURE

Type of Capital	Percent	Cost Rate	Wt. Average Cost Rate	Pre-tax Wt. Av. Cost Rate
Common Equity	54.50%	11.50%	6.27%	10.45%
Long-term Debt	45.50%	5.41%	2.46%	2.46%
	100.00%			**12.91%**

HISTORICAL CAPITAL STRUCTURE

Type of Capital	Percent	Cost Rate	Wt. Average Cost Rate	Pre-tax Wt. Av. Cost Rate
Common Equity	45.00%	11.50%	5.18%	8.63%
Long-term Debt	55.00%	5.41%	2.98%	2.98%
	100.00%			**11.60%**

OVERALL COST OF CAPITAL DIFFERENCE =	**1.31%**
COMPANY REQUESTED RATE BASE =	**$4.467 Bill.**
ANNUAL RATE IMPACT OF CAPITAL STRUCTURE SHIFT =	**$58,378,479**

ARIZONA PUBLIC SERVICE COMPANY
PINNCALE WEST CAPITAL CORPORATION
CONSOLIDATED CAPITAL STRUCTURE

AMOUNT (000,000)

Type of Capital	Mar-05	Jun-05	Sep-05	Dec-05	Mar-06	**Average**
Common Equity	$2,993.0	$3,253.4	$3,540.5	$3,425.0	$3,210.0	**$3,284**
Long-term Debt	$3,094.2	$3,424.7	$3,369.1	$2,993.2	$3,166.3	**$3,210**
Short-term Debt	$63.3	$93.4	$59.7	$15.6	$10.6	**$49**
TOTAL	$6,150.5	$6,771.5	$6,969.3	$6,433.8	$6,386.9	**$6,542**

PERCENTAGE

Type of Capital	Mar-05	Jun-05	Sep-05	Dec-05	Mar-06	**5 Quarter Average**
Common Equity	48.66%	48.05%	50.80%	53.23%	50.26%	**50.20%**
Long-term Debt	50.31%	50.58%	48.34%	46.52%	49.57%	**49.06%**
Short-term Debt	1.03%	1.38%	0.86%	0.24%	0.17%	**0.74%**
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Data from Company response to RUCO-3-1.

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC UTILITY INDUSTRY COMMON EQUITY RATIOS

ELECTRIC COMPANIES	EQUITY RATIO	COMBINATION GAS & ELECTRIC COMPANIES	EQUITY RATIO
Allegheny Energy	31%	AES Corp.	NM
ALLETE	61%	Alliant Energy	54%
American Electric Power	45%	Ameren Corp.	50%
Central Vermont P.S.	63%	Aquilla	40%
Cleco Corporation	52%	Avista Corp.	44%
DPL, Inc.	35%	Black Hills Corporation	51%
Duquesne Light Holdings	35%	CenterPoint Energy	NM
Edison International	39%	CH Energy Group	57%
El Paso Electric Co.	48%	CMS Energy Corp.	22%
Empire District Electric	46%	Consolidated Edison	47%
FirstEnergy Corp.	45%	Constellation Energy	44%
FPL Group	44%	Dominion Resources	38%
Great Plains Energy	48%	DTE Energy Company	43%
Green Mountain Power	56%	Duke Energy	49%
Hawaiian Electric Industries	37%	Energy East Corp.	42%
IDACORP	49%	Entergy Corp.	46%
Maine & Maritimes Corp.	49%	Excelon Corp.	39%
OGE Energy	51%	Florida Pub. Utilities	46%
Otter Tail Power	59%	MDU Resources	61%
Pinnacle West Capital Corp.	48%	MGE Resources	55%
Progerss Energy	41%	NiSource Inc.	45%
Southern Co.	42%	Northeast Utilities	43%
TXU Corp.	NM	Northwestern Corp.	52%
UIL Holdings	50%	NSTAR	33%
Westar Energy	48%	Pepco Holdings	41%
		PG&E Corp.	42%
		PNM Resources	38%
		PPL Corp.	40%
		Public Service Ent. Group	34%
		Puget Energy	44%
INDUSTRY MEDIAN	**44%**	SCANA Corp.	43%
		SEMPRA Energy	54%
		Sierra Pacific Resources	32%
		TECO Energy	29%
		UniSource Energy	32%
		Unitil Corp.	38%
		Vectren Corp.	44%
		Wisconsin Energy Corp.	42%
		WPS Resources	47%
		Xcel Energy Inc.	43%

Data from AUS Utility Reports, June 2006, pp. 8, 12.

ARIZONA PUBLIC SERVICE COMPANY
RATEMAKNG CAPITAL STRUCTURE

Type of Capital	PERCENT	COST RATE*	WT. AVG. COST RATE
Common Equity	50.00%	-	-
Long-term Debt	50.00%	5.41%	2.71%
Totals	100.00%		

*Cost rate from Company filing, Schedule D-2.

Exhibit__(SGH-1)
Schedule 3

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC UTILITY SAMPLE GROUP SELECTION

	Company Name	Revenues % Electric	Pending Merger?	Recent Div. Cut?	Generation Assets?	Stable Book Value?	Bond Rating S&P	Bond Rating Moody's	Selected
	SCREEN	≥70%	no	no	yes	yes	A- to BBB-		
EAST									
e	Allegheny Energy	84	no	yes	yes	no	BBB-	Baa3	
e+g	CH Energy	53	no	no	yes	yes	BBB	Baa2	
e	Central Vermont P. S.	100	no	no	yes	yes	BBB	-	√
e+g	Consolidated Edison	64	no	no	no	yes	A	A1	
e+g	Constellation Energy	11	yes	no	yes	yes	A-	A3	
e	Duquesne Light Holdings	79	no	yes	no	no	BBB+	Baa1	
e+g	Dominion Resources	30	no	no	yes	yes	BBB+	A3	
e+g	Duke Energy	36	yes	no	yes	yes	BBB	Baa1	
e+g	Energy East Corp.	56	no	no	yes	yes	BBB+	A3	
e+g	Excelon Corp.	88	yes	no	yes	yes	BBB+	A3	
e	FPL Group	78	yes	no	yes	yes	A	Aa3	
e	FirstEnergy Corp.	79	no	no	yes	yes	BBB	Baa1	√
e	Green Mountain Power	100	no	no	yes	yes	BBB	Baa1	√
e+g	Northeast Utilities	70	no	no	yes	yes	BBB	Baa1	√
e+g	NSTAR	79	no	no	no	yes	A+	A1	
e+g	PPL Corporation	69	no	no	yes	no	A-	Baa2	
e+g	Pepco Holdings, Inc.	67	no	no	no	no	A-	A3	
e	Progress Energy	78	no	no	yes	yes	BBB	A3	√
e+g	Public Service Ent. Gp.	62	yes	no	yes	yes	A-	A3	
e+g	SCANA Corp.	39	no	no	yes	yes	A-	A1	
e	Southern Company	98	no	no	yes	yes	A+	A2	
e+g	TECO Energy	58	no	yes	yes	no	BBB-	Baa2	
e	UIL Holdings Corp.	67	no	no	no	yes	-	Baa2	
CENTRAL									
e	ALLETE	78	no	no	yes	no	A	Baa1	
e+g	Alliant Energy	70	no	no	yes	yes	A-	A2	
e+g	Ameren Corp.	80	no	no	yes	yes	A-	A3	√
e	American Eelectric Power	95	no	yes	yes	no	BBB	Baa1	
e+g	Aquila, Inc.	62	no	yes	yes	yes	B-	B2	
e+g	CMS Energy Corp.	43	no	yes	yes	no	BBB-	Baa3	
e+g	CenterPoint Energy	16	no	no	no	no	BBB	Baa2	
e	Cleco Corporation	95	no	no	yes	yes	BBB	Baa1	√
e	DPL Inc.	100	no	no	yes	yes	BBB-	Baa1	√
e+g	DTE Energy	55	no	no	yes	yes	BBB+	A3	
e	Empire District Electric	93	no	no	yes	yes	A-	Baa1	√
e+g	Entergy Corp.	80	no	no	yes	yes	BBB-	Baa2	√
e	Great Plains Energy	43	no	no	yes	yes	BBB	A2	
e+g	MGE Energy	60	no	no	yes	yes	AA-	Aa3	
e+g	NiSource Inc.	16	no	yes	yes	yes	BBB	Baa2	
e	OGE Energy Corp.	31	no	no	yes	yes	BBB+	Baa2	
e	Otter Tail Corp.	29	no	no	yes	yes	BBB+	A3	
e	TXU Corp.	22	no	yes	no	no	BBB-	Baa2	
e+g	Vectren Corp.	20	no	no	yes	yes	A	A3	
e+g	WPS Resources	14	no	no	yes	yes	A+	Aa2	
e	Westar Energy	91	no	yes	yes	no	BB+	Baa3	
e+g	Wisconsisn Energy	61	no	no	yes	yes	A-	A1	
WEST									
e+g	Avista Corp.	49	no	no	yes	yes	BBB-	Baa3	
e+g	Black Hills Corp.	22	no	no	yes	yes	BBB	Baa1	
e	Edison International	81	no	yes	yes	no	BBB+	A3	
e	El Paso Electric	98	no	yes	yes	yes	BBB	Baa2	
e	Hawaiian Electric	82	no	no	yes	yes	-	Baa2	√
e	IDACORP, Inc.	97	no	yes	yes	yes	A-	A3	
e+g	MDU Resources Group	5	no	no	yes	yes	A-	A2	
e+g	PG&E Corp.	71	no	yes	yes	no	BBB	Baa1	
e+g	PNM Resources	76	no	no	yes	yes	BBB	Baa2	√
e	Pinnacle West Capital	74	no	no	yes	yes	BBB-	Baa1	√
e+g	Puget Energy, Inc.	61	no	no	yes	yes	BBB	Baa2	
e+g	Sempra Energy	45	no	no	yes	yes	A+	A1	
e+g	Sierra Pacific Resources	94	no	yes	yes	no	BB	Ba1	
e+g	UniSource Energy	87	yes	no	yes	yes	BBB-	Baa3	√
e+g	Xcel Energy, Inc.	75	no	yes	yes	no	A-	A3	

e= electric company; e+g=combination electric and gas company
Data from Value Line Ratings and Reports, March 3, March 31 and May 12, 2006 ; AUS Utility Reports, June 2006.

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
CV	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.0538	05.8%	0.31%	15.81	11.61	
2002	0.4286	09.3%	3.99%	16.83	11.74	
2003	0.3759	08.1%	3.04%	17.89	11.81	
2004	0.2640	06.8%	1.80%	18.49	12.19	
2005	-10.5000	nmf	nmf	17.45	12.28	
AVERAGE GROWTH			2.28%	2.50%		1.41%
2006	0.1636	07.5%	1.23%		10.35	-15.72%
2007	0.3429	09.5%	3.26%		10.45	-0.50%
2009-2011	0.4743	10.5%	4.98%	nmf	10.70	-2.72%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
FE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.4718	08.9%	4.20%	24.86	297.64	
2002	0.4094	10.5%	4.30%	23.92	297.64	
2003	-0.0204	05.4%	-0.11%	25.13	329.84	
2004	0.3105	10.6%	3.29%	26.04	329.84	
2005	0.3979	10.2%	4.06%	27.86	329.84	
AVERAGE GROWTH			3.15%	6.00%		2.60%
2006	0.5273	13.0%	6.85%		329.84	0.00%
2007	0.5325	13.0%	6.92%		329.84	0.00%
2009-2011	0.4889	11.5%	5.62%	6.50%	329.84	0.00%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
GMP	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	-0.3564	10.7%	-3.81%	17.81	5.69	
2002	0.6939	12.3%	8.53%	18.51	4.95	
2003	0.6219	10.3%	6.41%	19.85	5.03	
2004	0.5810	10.1%	5.87%	21.32	5.14	
2005	0.5215	09.4%	4.90%	22.43	5.23	
AVERAGE GROWTH			4.38%	3.00%		-2.09%
2006	0.4909	09.0%	4.42%		5.30	1.34%
2007	0.4233	09.5%	4.02%		5.35	1.14%
2009-2011	0.3156	10.5%	3.31%	2.50%	5.50	1.01%

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PGN	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.3761	11.5%	nmf	27.45	218.73	
2002	0.4323	12.1%	5.23%	28.73	232.43	
2003	0.3372	10.9%	3.68%	30.26	246.00	
2004	0.2516	09.9%	2.49%	30.9	247.00	
2005	0.1905	09.0%	1.71%	31.9	252.00	
AVERAGE GROWTH			3.28%	6.50%		3.60%
2006	0.2375	09.5%	2.26%		254.00	0.79%
2007	0.2424	09.5%	2.30%		256.00	0.79%
2009-2011	0.2294	09.0%	2.06%	3.00%	261.00	0.70%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
AEE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.2551	14.0%	3.57%	24.26	138.05	
2002	0.0451	09.9%	0.45%	24.93	154.10	
2003	0.1911	11.6%	2.22%	26.73	162.90	
2004	0.0993	09.1%	0.90%	29.71	195.20	
2005	0.1885	09.7%	1.83%	31.09	204.70	
AVERAGE GROWTH			1.79%	5.00%		10.35%
2006	0.1533	09.5%	1.46%		207.20	1.22%
2007	0.2063	10.0%	2.06%		209.80	1.24%
2009-2011	0.2303	09.5%	2.19%	3.00%	216.80	1.16%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
CNL	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.4238	14.6%	6.19%	10.69	44.96	
2002	0.4079	13.1%	5.34%	11.77	47.04	
2003	0.2857	12.5%	3.57%	10.09	47.18	
2004	0.3182	11.9%	3.79%	10.83	49.62	
2005	0.3662	10.7%	3.92%	13.69	49.99	
AVERAGE GROWTH			4.56%	4.00%		2.69%
2006	0.3077	08.5%	2.62%		54.25	8.52%
2007	0.3571	08.5%	3.04%		60.50	10.01%
2009-2011	0.4286	09.0%	3.86%	8.00%	68.00	6.35%

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
DPL	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.4598	27.8%	12.78%	6.31	126.50	
2002	-0.3056	10.8%	-3.30%	6.38	126.50	
2003	0.1376	14.6%	2.01%	7.13	126.50	
2004	0.4696	20.7%	9.72%	8.25	126.50	
2005	0.0680	11.9%	0.81%	8.14	127.53	
AVERAGE GROWTH			4.40%	-1.00%		0.20%
2006	0.3103	26.5%	8.22%		112.00	-12.18%
2007	0.3882	26.0%	10.09%		112.00	-6.29%
2009-2011	0.3556	18.5%	6.58%	1.50%	120.00	-1.21%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
EDE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	-1.1695	03.9%	-4.56%	13.58	19.76	
2002	-0.0756	07.8%	-0.59%	14.59	22.57	
2003	0.0078	07.8%	0.06%	15.17	24.98	
2004	-0.4884	05.8%	-2.83%	14.76	25.70	
2005	-0.3913	06.0%	-2.35%	15.08	26.08	
AVERAGE GROWTH			-2.05%	2.00%		7.18%
2006	-0.2190	06.0%	-1.31%		30.15	15.61%
2007	0.1172	09.0%	1.06%		31.20	9.38%
2009-2011	0.1467	09.5%	1.39%	2.00%	33.00	4.82%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
ETR	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.5844	09.3%	5.44%	33.78	220.73	
2002	0.6359	10.9%	6.93%	35.24	222.42	
2003	0.5664	09.8%	5.55%	38.02	228.90	
2004	0.5191	11.0%	5.71%	38.26	216.83	
2005	0.5091	11.9%	6.06%	35.71	207.50	
AVERAGE GROWTH			5.94%	4.50%		-1.53%
2006	0.5304	11.5%	6.10%		208.20	0.34%
2007	0.5167	11.5%	5.94%		208.60	0.26%
2009-2011	0.4717	10.5%	4.95%	5.00%	215.80	0.79%

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
HE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.2250	11.6%	2.61%	13.06	71.20	
2002	0.2346	11.3%	2.65%	14.21	73.62	
2003	0.2152	10.8%	2.32%	14.36	75.84	
2004	0.0882	08.9%	0.79%	15.01	80.69	
2005	0.1507	09.7%	1.46%	15.02	80.98	
AVERAGE GROWTH			1.97%	3.00%		3.27%
2006	0.1733	10.0%	1.73%		81.20	0.27%
2007	0.2000	10.0%	2.00%		81.40	0.26%
2009-2011	0.2914	10.0%	2.91%	2.50%	82.00	0.25%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PNM	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.7969	15.4%	12.27%	17.25	58.68	
2002	0.4673	06.5%	3.04%	16.60	58.68	
2003	0.4696	06.3%	2.96%	17.84	60.39	
2004	0.5594	08.0%	4.48%	18.19	60.46	
2005	0.5031	08.2%	4.13%	18.70	68.79	
AVERAGE GROWTH			5.37%	4.50%		4.05%
2006	0.4788	08.5%	4.07%		68.80	0.01%
2007	0.4743	08.5%	4.03%		70.80	1.45%
2009-2011	0.4211	08.5%	3.58%	4.00%	74.00	1.47%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PNW	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.5842	12.5%	7.30%	29.46	84.83	
2002	0.3557	08.0%	2.85%	29.44	91.26	
2003	0.3135	08.1%	2.54%	31.00	91.29	
2004	0.2907	08.0%	2.33%	32.14	91.79	
2005	0.1645	06.5%	1.07%	34.57	99.08	
AVERAGE GROWTH			3.22%	4.00%		3.96%
2006	0.3233	08.5%	2.75%		99.10	0.02%
2007	0.3735	09.0%	3.36%		99.10	0.01%
2009-2011	0.3155	09.0%	2.84%	3.50%	99.10	0.00%

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
UNS	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2001	0.7765	14.3%	11.10%	12.68	33.50	
2002	0.4845	07.6%	3.68%	13.05	33.58	
2003	0.5385	08.4%	4.52%	15.97	33.79	
2004	0.5115	07.9%	4.04%	16.95	34.26	
2005	0.4154	07.5%	3.12%	17.68	34.87	
AVERAGE GROWTH			5.29%	12.00%		1.01%
2006	0.5333	09.5%	5.07%		35.30	1.23%
2007	0.5027	09.5%	4.78%		35.70	1.18%
2009-2011	0.4051	08.5%	3.44%	5.00%	36.90	1.14%

Data from Value Line Ratings & Reports May 12, June 2, and June 30, 2006.

ARIZONA PUBLIC SERVICE COMPANY

DCF GROWTH RATES
ELECTRIC UTILITIES

COMPANY	br	+	sv=g*(1-(1/(M/B)))		=	g
CV	4.00%	+	0.00%	(1 - (1/ 1.05)))	=	4.00%
FE	5.50%	+	0.00%	(1 - (1/ 1.77)))	=	5.50%
GMP	5.00%	+	0.00%	(1 - (1/ 1.30)))	=	5.00%
PGN	3.00%	+	1.50%	(1 - (1/ 1.29)))	=	3.34%
AEE	3.75%	+	2.50%	(1 - (1/ 1.58)))	=	4.66%
CNL	4.75%	+	4.00%	(1 - (1/ 1.52)))	=	6.11%
DPL	6.50%	+	0.00%	(1 - (1/ 4.51)))	=	6.50%
EDE	3.00%	+	5.00%	(1 - (1/ 1.37)))	=	4.35%
ETR	6.00%	+	0.00%	(1 - (1/ 1.77)))	=	6.00%
HE	3.50%	+	1.00%	(1 - (1/ 1.77)))	=	3.93%
PNM	5.75%	+	2.00%	(1 - (1/ 1.31)))	=	6.23%
PNW	5.00%	+	1.00%	(1 - (1/ 1.11)))	=	5.10%
UNS	5.25%	+	1.00%	(1 - (1/ 1.64)))	=	5.64%

Average Market-to-Book Ratio = 1.69

CV	=	Central Vermont P. S.
FE	=	FirstEnergy Corp.
GMP	=	Green Mountain Power
PGN	=	Progress Energy
AEE	=	Ameren Corp.
CNL	=	Cleco Corporation
DPL	=	DPL, Inc.
EDE	=	Empire District Electric
ETR	=	Entergy Corp.
HE	=	Hawaiian Electric
PNM	=	PNM Resources
PNW	=	Pinnacle West Capital
UNS	=	Unisource Energy

g*= expected growth in number of shares outstanding

ARIZONA PUBLIC SERVICE COMPANY

GROWTH RATE COMPARISON
ELECTRIC UTILITIES

	DCF	Value Line Projected			Reuters	Value Line Historic			Reuters & VL	5-yr Compound Hist.		
COMPANY	Growth	EPS	DPS	BVPS	EPS	EPS	DPS	BVPS	AVGS.	EPS	DPS	BVPS
CV	4.00%	11.50%	-1.00%	1.00%	n/a	1.00%	0.50%	2.50%	2.58%	3.41%	0.89%	0.98%
FE	5.50%	11.50%	5.00%	6.50%	4.43%	0.00%	2.50%	6.00%	5.13%	6.27%	3.94%	3.76%
GMP	5.00%	3.50%	10.00%	2.50%	n/a	nmf	5.00%	3.00%	4.80%	3.19%	-15.17%	5.38%
PGN	3.34%	1.50%	2.00%	3.00%	2.87%	4.50%	3.00%	6.50%	3.34%	-1.38%	2.66%	3.63%
AEE	4.66%	1.50%	0.00%	3.00%	5.20%	0.50%	0.00%	5.00%	2.17%	-2.53%	0.00%	5.53%
CNL	6.11%	4.50%	2.00%	8.00%	8.00%	1.00%	2.00%	4.00%	4.21%	-2.95%	0.68%	6.58%
DPL	6.50%	5.50%	3.50%	1.50%	7.50%	-1.00%	0.50%	-1.00%	2.36%	-3.58%	1.25%	-1.33%
EDE	4.35%	6.50%	0.00%	2.00%	2.50%	-5.00%	0.00%	2.00%	1.14%	12.22%	0.00%	2.75%
ETR	6.00%	5.00%	7.00%	5.00%	7.17%	10.00%	7.50%	4.50%	6.60%	8.35%	11.03%	3.36%
HE	3.93%	3.00%	0.00%	2.50%	2.90%	1.00%	0.00%	3.00%	1.77%	-1.28%	0.00%	3.22%
PNM	6.23%	5.50%	8.50%	4.00%	11.45%	-1.00%	5.00%	4.50%	5.42%	-8.76%	10.17%	2.48%
PNW	5.10%	6.00%	5.00%	3.50%	7.60%	-4.50%	6.50%	4.00%	4.01%	-4.00%	5.82%	3.83%
UNS	5.64%	7.00%	9.50%	5.00%	n/a	5.00%	0.00%	12.00%	6.42%	0.11%	16.00%	8.20%
		5.58%	3.96%	3.65%		0.96%	2.50%	4.31%		0.70%	2.87%	3.72%
AVERAGES	5.10%		4.40%		5.96%		2.59%		3.84%		2.43%	

Zack's growth rates: CV-n/a, FE-4.9%, GMP-n/a, PGN-3.6%, AEE-6.0%, CNL-8%, DPL-7.0%, EDE-n/a, ETR-7.5%, HE-5.2%, PNM-8.3%, PNW-6.8%, and UNS-n/a. Zack's average earnings growth = 6.4%.

ARIZONA PUBLIC SERVICE COMPANY

STOCK PRICE, DIVIDENDS, YIELDS
ELECTRIC UTILITIES

COMPANY	AVG. STOCK PRICE 5/22/06-7/3/06 (PER SHARE)		ANNUALIZED DIVIDEND (PER SHARE)	DIVIDEND YIELD
CV	$17.43		$0.92	5.28%
FE	$52.99	*	$1.90	3.58%
GMP	$30.07		$1.12	3.72%
PGN	$42.25		$2.42	5.73%
AEE	$50.06		$2.54	5.08%
CNL	$22.28		$0.90	4.04%
DPL	$26.64		$1.00	3.75%
EDE	$21.29		$1.28	6.01%
ETR	$70.62		$2.16	3.06%
HE	$27.02		$1.24	4.59%
PNM	$25.64		$0.88	3.43%
PNW	$39.56	*	$2.10	5.31%
UNS	$30.75		$0.84	2.73%
			AVERAGE	**4.33%**

*Quarterly dividend increased by (1+g) , shown in Schedule 5.

ARIZONA PUBLIC SERVICE COMPANY

DCF COST OF EQUITY CAPITAL
ELECTRIC UTILITIES

COMPANY	DIVIDEND YIELD Schedule 6	GROWTH RATE Schedule 5	DCF COST OF EQUITY CAPITAL
CV	5.28%	4.00%	9.28%
FE	3.58%	5.50%	9.08%
GMP	3.72%	5.00%	8.72%
PGN	5.73%	3.34%	9.06%
AEE	5.08%	4.66%	9.75%
CNL	4.04%	6.11%	10.15%
DPL	3.75%	6.50%	10.25%
EDE	6.01%	4.35%	10.36%
ETR	3.06%	6.00%	9.06%
HE	4.59%	3.93%	8.52%
PNM	3.43%	6.23%	9.66%
PNW	5.31%	5.10%	10.41%
UNS	2.73%	5.64%	8.37%
		AVERAGE	**9.44%**
		STANDARD DEVIATION	**0.71%**

ARIZONA PUBLIC SERVICE COMPANY

CAPM COST OF EQUITY CAPITAL
ELECTRIC UTILITIES

k = rf + B (rm - rf)

[rf]* = 5.16%
[rm - rf]† = 4.90% (geometric mean)
[rm - rf]† = 6.50% (arithmetic mean)
average beta = 0.83

k = 5.16% + 0.83 (4.90%/6.50%)
k = 5.16% + 4.07%/5.40%
k = **9.23% / 10.56%**

*Current T-Bond yields, six-week average yield from Value Line Selection & Opinion (5/26/06-6/30/06)
†Geometric and arithmetic market risk premiums from Ibbotson Associates 2006 SBBI Yearbook, p. 28.

ARIZONA PUBLIC SERVICE COMPANY
PROOF

If market price exceeds book value,
the market-to-book ratio is greater than 1.0,
and the earnings-price ratio understates the cost of capital.

MP = market price
BV = book value
i = cost of equity capital
r = earned return
E = earnings

1. At MP = BV, $i = r = \frac{E}{MP}$.
2. $E = rBV$.
3. Then, $\frac{E}{MP} = \frac{rBV}{MP}$.
4. When BV < MP, i.e., $\frac{BV}{MP} < 1$, then,
   a. $\frac{E}{MP} < r$, since $\frac{E}{MP} = \frac{rBV}{MP} < r$, because $\frac{BV}{MP} < 1$;
   b. $i < r$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} < 1$, then $i < r$; and
   c. $\frac{E}{MP} < i$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} < 1$, then $\frac{E}{MP} < i$, because,
      1) $\frac{BV}{MP} < 1$, through MP increasing, and, if so, $\frac{E}{MP}$ decreases, therefore, $\frac{E}{MP} < i$, or
      2) $\frac{BV}{MP} < 1$, through BV decreasing, and, if so, given $E = rBV$, $\frac{E}{MP}$ decreases, therefore, $\frac{E}{MP} < i$.
5. Ergo, $\frac{E}{MP} < i < r$, the earnings-price ratio is lower than the cost of capital, which is lower than the earned return.

ARIZONA PUBLIC SERVICE COMPANY

MODIFIED EARNINGS-PRICE RATIO ANALYSIS
ELECTRIC UTILITIES

COMPANY	Reuters* 2007 Earnings (Per Share)	Market Price (Per share)	Earnings-Price Ratio		Current R.O.E. 2007	Projected R.O.E. 2009-2011
CV	$1.40	$17.43	8.03%		9.50%	10.50%
FE	$4.01	$52.99	7.57%		13.00%	11.50%
GMP	$2.15	$30.07	7.15%		9.50%	10.50%
PGN	$3.22	$42.25	7.62%		9.50%	9.00%
AEE	$3.82	$50.06	7.63%		10.00%	9.50%
CNL	$1.38	$22.28	6.19%		8.50%	9.00%
DPL	$1.65	$26.64	6.19%		26.00%	18.50%
EDE	$1.35	$21.29	6.34%		9.00%	9.50%
ETR	$5.50	$70.62	7.79%		11.50%	10.50%
HE	$1.86	$27.02	6.88%		10.00%	10.00%
PNM	$1.98	$25.64	7.72%		8.50%	8.50%
PNW	$3.32	$39.56	8.39%		9.00%	9.00%
UNS	$1.98	$30.75	6.44%		9.50%	8.50%
		AVERAGE	7.23%		11.04%	
		CURRENT M.E.P.R.		**9.13%**		
		AVERAGE	7.23%			10.35%
		PROJECTED M.E.P.R.			**8.79%**	

ARIZONA PUBLIC SERVICE COMPANY

MARKET-TO-BOOK RATIO ANALYSIS
ELECTRIC UTILITIES

k = R.O.E.(1-b)/(M/B) + g
[2006]

COMPANY									MARKET-TO-BOOK COST OF EQUITY
CV	k= 07.5%	(1-	0.3429	)/	1.05	+	4.00%	=	8.69%
FE	k= 13.0%	(1-	0.5273	)/	1.77	+	5.50%	=	8.97%
GMP	k= 09.0%	(1-	0.4909	)/	1.30	+	5.00%	=	8.53%
PGN	k= 09.5%	(1-	0.2375	)/	1.29	+	3.34%	=	8.96%
AEE	k= 09.5%	(1-	0.1533	)/	1.58	+	4.66%	=	9.77%
CNL	k= 08.5%	(1-	0.3077	)/	1.52	+	6.11%	=	9.99%
DPL	k= 26.5%	(1-	0.3103	)/	4.51	+	6.50%	=	10.55%
EDE	k= 06.0%	(1-	-0.2190	)/	1.37	+	4.35%	=	9.69%
ETR	k= 11.5%	(1-	0.5304	)/	1.77	+	6.00%	=	9.05%
HE	k= 10.0%	(1-	0.1733	)/	1.77	+	3.93%	=	8.61%
PNM	k= 08.5%	(1-	0.4788	)/	1.31	+	6.23%	=	9.60%
PNW	k= 08.5%	(1-	0.3233	)/	1.11	+	5.10%	=	10.27%
UNS	k= 09.5%	(1-	0.5333	)/	1.64	+	5.64%	=	8.35%
								AVERAGE	**9.31%**
								STANDARD DEVIATION	**0.71%**

Note: Equity returns and retention ratios based on Value Line current year projections.

ARIZONA PUBLIC SERVICE COMPANY

MARKET-TO-BOOK RATIO ANALYSIS
ELECTRIC UTILITIES

k = R.O.E.(1-b)/(M/B) + g
[2009-2011]

COMPANY									MARKET-TO-BOOK COST OF EQUITY
CV	k= 10.5%	(1-	0.4743	)/	1.05	+	4.00%	=	9.26%
FE	k= 11.5%	(1-	0.4889	)/	1.77	+	5.50%	=	8.82%
GMP	k= 10.5%	(1-	0.3156	)/	1.30	+	5.00%	=	10.53%
PGN	k= 09.0%	(1-	0.2294	)/	1.29	+	3.34%	=	8.72%
AEE	k= 09.5%	(1-	0.2303	)/	1.58	+	4.66%	=	9.30%
CNL	k= 09.0%	(1-	0.4286	)/	1.52	+	6.11%	=	9.50%
DPL	k= 18.5%	(1-	0.3556	)/	4.51	+	6.50%	=	9.14%
EDE	k= 09.5%	(1-	0.1467	)/	1.37	+	4.35%	=	10.27%
ETR	k= 10.5%	(1-	0.4717	)/	1.77	+	6.00%	=	9.13%
HE	k= 10.0%	(1-	0.2914	)/	1.77	+	3.93%	=	7.95%
PNM	k= 08.5%	(1-	0.4211	)/	1.31	+	6.23%	=	9.97%
PNW	k= 09.0%	(1-	0.3155	)/	1.11	+	5.10%	=	10.64%
UNS	k= 08.5%	(1-	0.4051	)/	1.64	+	5.64%	=	8.73%
								AVERAGE	**9.38%**
								STANDARD DEVIATION	**0.79%**

Note: Equity returns and retention ratios based on Value Line three- to five-year projections.

ARIZONA PUBLIC SERVICE COMPANY
LEVERAGE/BETA ADJUSTMENT TO THE COST OF EQUITY CAPITAL

COMPANY	COMMON EQUITY	FIXED INCOME CAPITAL	M/B RATIO	MKT. VALUE DEBT(1-t)/EQ.
Central Vermont P. S.	63.00%	37.00%	1.05	0.36
FirstEnergy Corp.	45.00%	55.00%	1.77	0.45
Green Mountain Power	56.00%	44.00%	1.30	0.39
Progress Energy	41.00%	59.00%	1.29	0.73
Ameren Corp.	50.00%	50.00%	1.58	0.41
Cleco Corporation	52.00%	48.00%	1.52	0.39
DPL, Inc.	35.00%	65.00%	4.51	0.27
Empire District Electric	46.00%	54.00%	1.37	0.56
Entergy Corp.	46.00%	54.00%	1.77	0.43
Hawaiian Electric	37.00%	63.00%	1.77	0.63
PNM Resources	38.00%	62.00%	1.31	0.81
Pinnacle West Capital	48.00%	52.00%	1.11	0.63
Unisource Energy	32.00%	68.00%	1.64	0.84
AVERAGES	45.31%	54.69%	1.69	0.53
TARGET CAP. STRUCTURE	50.00%	50.00%	1.69	**0.38**

AVERAGE (LEVERED) UTILITY BETA = 0.83

Beta (Unlevered) = Beta (Levered)/(1+D(1-t)/E)

Beta (Unlevered)= 0.83/(1+.53)= **0.54**

Beta (Relevered)= Beta (Unlevered)*(1+D(1-t)/E)

Beta (Relevered)= 0.54(1.38)= **0.75**

IMPACT ON COST OF EQUITY CAPITAL

	Measured Beta	0.830
	Relevered Beta	0.751
[1]	Diff. in Beta	0.079
[2]	Market Risk Premium (rm-rf) =	4% to 6%

Average Cost of equity impact = [1] x [2] = **0.32% to 0.48%**

ARIZONA PUBLIC SERVICE COMPANY
OVERALL COST OF CAPITAL

Type of Capital	PERCENT	COST RATE	WT. AVG. COST RATE
Common Equity	50.00%	9.25%	4.63%
Total Debt	50.00%	5.41%	2.71%
Totals	100.00%		**7.33%**

PRE-TAX INTEREST COVERAGE* = 3.85x

*Assuming the Company experiences, prospectively, a combined income tax rate of 40%, the pre-tax overall return would be 10.41% [7.33%-(2.71%)=4.63% /(1-40%) = 7.71%+(2.71%)]. That pre-tax overall return (10.41%), divided by the weighted cost of debt (2.71%), indicates a pre-tax interest coverage level of 3.85 times.

ARIZONA CORPORATION COMMISSION

IN THE MATTER

of the
Application of Arizona Public Service Company for a
Hearing to Determine the Fair Value of the Utility Property of the Company
for Ratemaking Purposes, to Fix a Just and Reasonable
Rate of Return Thereon, to Approve Rate Schedules Designed to Develop
Such Return, and to Amend Decision No. 67744

Docket No. E-01345A-05-0816

Direct Testimony of
David A. Schlissel

On behalf of
The Residential Utility Consumer Office

PUBLIC VERSION
Protected Information Redacted

August 18, 2006

Q. Mr. Schlissel, please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Staff of the Kansas State Corporation Commission, the Arkansas Public Service Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

Q. Mr. Schlissel, have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified in Dockets Nos. U-1345-85, U-1345-90-007, and E-01345A-01-0822. I also filed testimony in Dockets Nos. U-1551-93-272 and E-01345A-03-0437 but those cases were settled before hearings were held.

Q. What is the purpose of your testimony?

A. Synapse was retained by RUCO to investigate the following issues:

- Whether APS' acquisition of the Sundance Generating Station was prudent.
- Whether the amounts that APS is requesting for Operating & Maintenance expenditures ("O&M") for the PWEC Units and the Sundance Plant are reasonable.
- The generation and associated costs included in APS' base rate application.

My testimony will address the first two of these issues. The testimony of my colleague from Synapse, Richard Hornby, will address the remaining issue.

Q. Please explain how you have conducted your investigations and analyses of the prudence of APS' acquisition of the Sundance Plant and the reasonableness of the requested O&M for the PWEC and Sundance units.

A. I reviewed the Company's Application, supporting testimony and exhibits and workpapers. I also reviewed APS' responses to the discovery submitted by RUCO and the other active parties in this docket. In addition, I reviewed the testimony filed in ACC Dockets Nos. E-01345A-04-0407 and L-00000W-00-0107 and the Commission's Order in those Dockets.

Q. Please summarize your findings.

A. I have found that:

1. APS' acquisition of the Sundance Plant was reasonable and prudent.
2. The Company's requested PWEC Unit O&M is unreasonably high and should be reduced by at least $5,767,852.
3. The Company's requested Sundance Plant O&M also is unreasonably high and should be reduced by [Redacted].

Q. Please explain the basis for your conclusion that APS' acquisition of the Sundance Plant was reasonable and prudent.

A. My conclusion that APS' acquisition of the Sundance Plant was reasonable and prudent is based on the following findings:

1. APS shows a need for additional capacity.
2. The acquisition of the CT capacity at Sundance, along with the Company's existing nuclear, coal and combined cycle capacity, gives APS flexibility in meeting peak demands.
3. The process that APS used to select the Sundance Plant appears to have been thorough and reasonable.
4. The price of the Sundance Plant is reasonable compared to the other available alternatives.
5. Economic analyses suggest that the acquisition of the Sundance Plant will produce net economic benefits compared to the other available alternatives.

Q. Have you identified any flaws in the Company's pro forma adjustment of PWEC Unit O&M?

A. Yes. There appear to be several flaws that lead APS to overinflate the amount of required PWEC Unit O&M:

1. APS began with what are designated as the actual PWEC 2004 O&M expenditures instead of the Units' O&M expenditures for the October 2004-September 2005 test year.

2. APS makes a pro forma adjustment for variable O&M that began with the PWEC Units' actual 2004 generation and reflected projected generation levels from APS' 2005 Long Range Forecast that are substantially [Redacted] than the more recent 2006 rate case generation forecasts.

Q. Have you adjusted to correct for these flaws?

A. Yes. My adjustments are shown in Exhibit DAS-2. These adjustments reduce the level of required PWEC Unit O&M by at least $5,767,852.

Q. Do there appear to be any inconsistencies between the amounts of 2004 PWEC Unit O&M used in the Company's pro forma adjustment and the levels reported in APS' data responses?

A. Yes. APS' workpapers reflect total PWEC 2004 routine O&M (plants only) of $22,391,000.[1] This figure includes APS-PWEC Affiliate Charges for auxiliary power and common facilities. Data Request UTI-3-172 asked APS to provide comparable actual data by the categories shown on Workpaper LLR_WP13, page 8 of 11 G by PWEC Unit by year for all years that each unit has been in service.

As I was preparing this testimony, I realized that the 2004 calendar year figures provided in response to Data Request UTI-3-172 show a routine O&M total for the PWEC Units of $21,049,181, or approximately $1.3 million less than the comparable figure used in the derivation of the required PWEC Unit O&M.[2] I hope that APS can explain this apparent inconsistency in its rebuttal testimony.

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1 APS Workpaper LLR_WP13, page 8 of 11 G.

2 Bates Page Number APS 10143.

Q. Was APS requested to provide the test year actual PWEC Unit O&M expenses in the same categories in which historical expenses had been used in Workpaper LLR_WP 13, page 8 of 11 G and that had been provided in response to Data Request UTI-3-172?

A. Yes. Data Request UTI-11-329 asked APS to provide the test year PWEC O&M expenses in the identical categories incurred by PWEC and APS that had been presented in the Company's response to UTI-3-172.

Q. How did the test year PWEC Unit O&M compare to the 2004 O&M expenses used in Workpaper LLR_WP13, page 8 of 11 G that were used by APS to derive the required levels of PWEC Unit O&M?

A. The test year PWEC Unit routine O&M expenses provided in response to UTI-11-329 (including APS-PWEC affiliate charges for auxiliary power and common facilities) were $21,332,111, or approximately $1 million lower than the $22,391,000 figure used by APS to calculate the required level of O&M in this proceeding.[3]

Q. APS' methodology for determining the level of required PWEC O&M in this proceeding involved subtracting out the APS-PWEC affiliate charges for auxiliary power and common facilities. Were you able to do so for the test year O&M provided by the Company in response to Data Request UTI-11-329?

A. No. Even though APS' response to UTI-3-172 shows that such common facilities charges were incurred in 2004 and while PWEC owned the plants during the months of January-July 2005, they were not separately identified in APS' response to UTI-11-329. Therefore, I did not subtract out those common facilities charges when I made the adjustments presented in my Exhibit DAS-2.

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[3] Bates Page Number APS09162.

Q. What would be the effect of eliminating these common facilities charges in your calculations shown in Exhibit DAS-2?

A. Subtracting the common facilities charges would reduce the level of required test year PWEC Unit O&M.

Q. Is it possible that APS already has eliminated the common facilities charges from the figures provided in response to UTI-11-329?

A. Yes. That is why I did not make any adjustment in Exhibit DAS-2. I hope that APS can address this issue in its rebuttal testimony. Then I will be make to make any needed revisions to the calculations shown in Exhibit DAS-2 as part of my surrebuttal testimony.

Q. Why does APS make a pro forma adjustment to variable O&M costs?

A. APS makes the adjustment to reflect the projection that future PWEC Unit generation levels will be higher than the units produced in 2004.

Q. How did APS make this pro forma adjustment?

A. APS' pro forma adjustment to the PWEC Unit variable O&M was provided in the Company's response to Data Request UTI-3-172.[4]

APS calculated the adjustment by determining the difference between the actual generation at each of the PWEC Units during 2004 and the average projected generation at each unit during the years 2006-2011. APS then multiplied this difference by a $/MWH variable O&M cost that was specific to each of the PWEC Units.

Q. Do you agree with this pro forma adjustment?

A. No. The specific variable O&M adjustment that APS made was unreasonable in two ways: First, APS based the adjustment on the average generation projected

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4 At Bates Page Number APS1-143, page 2 of 6.

for each PWEC Unit for the years 2006-2011. Second, APS based its pro forma variable O&M adjustment on the future generation projections that were included in its 2005 Long Range Forecast. Together, these flaws led APS to overstate the necessary pro forma adjustment.

Q. Why do you believe that it was a flaw for APS to base its variable O&M adjustment on the average projected generation of each of the PWEC Units during the years 2006-2011?

A. Pro forma adjustments from test year plant performance should be based on very specific known and measurable information. I do not believe that speculative forecasts of generating unit performance five or six years in the future should form the basis for such adjustments in the context of the APS rate case. Instead, more near-term generation forecasts from the years 2006-2008 should be used.

Q. Why don't you just recommend that the projected generation for each PWEC Unit for the year 2006 be used?

A. The Company's 2006 Rate Case generation projections forecast that the generation of each of the PWEC Units will be [Redacted] in 2007 and 2008 than in 2006. Therefore, on its own, 2006 would not be a reasonable representative year on which to base the variable O&M adjustment.

Q. Why do you believe it was a flaw for APS to use the projected levels of generation from its 2005 Long Range Forecast in the development of its variable O&M pro forma adjustment?

A. As shown in Tables 1 through 4 below, the Company's more recent 2006 Rate Case projections for generation at the Redhawk, West Phoenix CC 4 and CC 5 PWEC units are [Redacted] than the projections included in APS' 2005 Long Range Forecast.[5]

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[5] APS' Confidential Response to Data Request RUCO 4.8, Bates Page No. APS 10222.

Table 1: Projected Saguaro CT 3 Generation (MWH)

Forecast	2006	2007	2008	2006-2008 Average
2005 LRF				
2006 Rate Case				

Table 2: Projected West Phoenix CC 4 Generation (MWH)

Forecast	2006	2007	2008	2006-2008 Average
2005 LRF				
2006 Rate Case				

Table 3: Projected West Phoenix CC5 Generation (MWH)

Forecast	2006	2007	2008	2006-2008 Average
2005 LRF				
2006 Rate Case				

Table 4: Projected Redhawk Generation (MWH)

Forecast	2006	2007	2008	2006-2008 Average
2005 LRF				
2006 Rate Case				

Using the older, and [Redacted], generation projections from APS' 2005 LRF would over inflate the variable O&M adjustment and create the potential for APS to over recover the PWEC Unit O&M. Consequently, the more recent 2006 Rate Case generation figures should be used in the derivation of the pro forma variable O&M adjustment.

Q. What are the results when you adjust the Company's requested PWEC Unit O&M to reflect the use of test year O&M and the 2006 Rate Case generation figures to calculate the pro forma variable O&M adjustment in place of the generation figures from the 2005 Long Range Forecast?

A. As shown in Exhibit DAS-2, these adjustments reduce the level of required PWEC Unit O&M by at least $5,767,852.[6]

Q. Why do you say by "at least" $5,767,852?

A. As I discussed earlier, it is not clear whether the test year PWEC Unit O&M provided in APS' response to Data Request UTI-11-329 included the APS-PWEC affiliate charges for common facilities. My calculated $5,767,852 adjustment would have to be increased to the extent that such affiliate charges have not already been excluded.

Q. Are you recommending any adjustment to APS' level of requested Sundance Plant O&M?

A. Yes. APS' methodology for calculating the required annual level of Sundance O&M includes a $2,750,000 adjustment for variable maintenance costs.[7] As shown on Workpaper LLR_WP14, page 10 of 11 G, this adjustment is based on the assumption that future generation at Sundance will average 630,000 MWH per year.

However, APS' 2006 Rate Case forecasts project that the Sundance Plant will generate only [ ] MWH in 2006, [ ] MWH in 2007, and [ ] MWH in 2008, for an average of [ ] MWH each year during the three year period. Replacing the estimated 630,000 MWH shown on Workpaper LLR_WP14, page 10 of 11 G, by this [ ] MWH figure, reduces the variable

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6 This $5,767,852 adjustment is the difference between the $26,336,276 Total O&M figure shown in Exhibit DAS-2, page 3 of 3, and the $32,104,128 figure shown on APS' Workpaper LLR_WP13, page 2 of 11 B.

7 Workpaper LLR_WP14, pages 1, 2, and 10 of 11.

O&M adjustment by [ ]. Consequently, the Total Company Sundance O&M figure shown on line 6 in Column W on Schedule C-2 page 4 of 11, would be reduced from $4,860,000 to [ ].

Q. Does this complete your testimony at this time?

A. Yes.

EXHIBIT DAS-1

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SUMMARY

I have worked for thirty years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric System Reliability - Evaluated whether new transmission lines and generation facilities were needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Analyzed power plant operating data from the NERC Generating Availability Data System (GADS). Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO_2 and CO_2. Examined whether new state emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proosed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Nuclear Power - Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates and cost collection plans. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Electric Industry Regulation and Markets - Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Evaluated the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets. Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and the auctions of power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Evaluated whether new electric generating facilities are used and useful. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than ninety proceedings before regulatory boards and commissions in twenty three states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY, AFFIDAVITS AND COMMENTS

South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

Georgia Public Service Commission (Docket No. 22449-U) – May 2006
Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006
The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005
The siting of a proposed 230 kV transmission line.

Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005
The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005
The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005
Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

Maine Public Utilities Commission (Docket No. 2005-17) – July 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

Maine Public Utilities Commission (Docket No. 2004-771) – March 2005
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company.

New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation.

California Public Utilities Commission (Application No. AO4-01-009) – August 2004
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004
Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004
Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

Connecticut Siting Council (Docket No. 272) – May 2004
Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004
Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004
Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003
The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115209) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001

The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs. Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities. Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

The 2003 Blackout: Solutions that Won't Cost a Fortune, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability. An Analysis for Riverkeeper, Inc. November 3, 2003.

The Impact of Converting Indian Point Units 2 and 3 to Closed-Cycle Cooling Systems with Cooling Towers on Energy's Likely Future Earnings. An Analysis for Riverkeeper, Inc. November 3, 2003.

Entergy's Lost Revenues During Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems. An Analysis for Riverkeeper, Inc. November 3, 2003.

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)

EXHIBIT DAS-2

PUBLIC VERSION

PROTECTED INFORMATION

REDACTED

PWEC Units
Test Year Operations and Maintenance Expenses

		Total PWEC O&M (Plants Only)
A	Routine O&M	$21,332,111
B	12 Year Average Overhaul Costs	$10,000,000
C	Sub-Total O&M Exps (A+B)	$31,332,111
D	A&G	$981,345
E	Total Including Aux Power, Common Facilities, A&G	$32,313,456
F	Exclude APS-PWEC Affiliate Charges - Auxiliary Power, Common Facilities Charge, A&G	$2,705,201
G	Total Excluding Aux Power, Common Facilities, A&G	$29,608,255
	Plus Proforma Variable O&M Adjustment	$827,893
	TOTAL O&M	$30,436,148
	TOTAL O&M Less Overhaul Costs	$20,436,148

Proforma PWEC Variable O&M

Unit	2006 Gen. (MWH)	2007 Gen (MWH)	2008 Gen (MWH)	2006-2008 Ave. (MWH)	Test Year Gen (MWH)	Diff. in Gen (MWH)	Variable O&M ($/MWH)	Variable O&M Delta ($)
Saguaro CT 3	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	$182,161
West Phoenix CC4	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	$422,000
West Phoenix CC5	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	$42,367
Redhawk	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	$181,365
							TOTAL	$827,893

Source: Confidential Responses to UTI-332(a) (APS 10222) and RUCO 4.8(APS09926)

Pro Forma Adjustment PWEC Units O&M

Aadjustment to test year operations to deduct costs recorded on APS books for the period August through September 2005

Other Operating Expenses

Operations Excluding Fuel Expenses:	$20,436,148
Less Operations record on APS	$3,841,197
Operations Pro Forma	$16,594,951
Maintenance	$10,000,000
Less Maintenance Record on APS	$258,675
Overhaul Pro Forma	$9,741,325
Total	$26,336,276

ARIZONA CORPORATION COMMISSION

IN THE MATTER

of the
Application of Arizona Public Service Company for a
Hearing to Determine the Fair Value of the Utility Property of the Company
for Ratemaking Purposes, to Fix a Just and Reasonable
Rate of Return Thereon, to Approve Rate Schedules Designed to Develop
Such Return, and to Amend Decision No. 67744

Docket No. E-01345A-05-0816

Direct Testimony of
J. Richard Hornby

On behalf of
The Residential Utility Consumer Office

August 18, 2006

Q. Please state your name, position and business address.

A. My name is J. Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. Please summarize your work experience and educational background.

A. I am a consultant specializing in planning, market structure, ratemaking and gas supply/fuel procurement in the electric and gas industries. Over the past twenty years I have has presented expert testimony and provided litigation support on these issues in approximately 100 proceedings in over thirty jurisdictions in the United States and Canada. Over this period my clients have included staff of public utility commissions, state energy offices, consumer advocate offices and marketers.

Prior to joining Synapse in 2006, I was a Principal with CRA International, formerly Tabors Caramanis & Associates. From 1986 to 1998 I worked with the Tellus Institute (formerly Energy Systems Research Group); initially as Manager of the Natural Gas Program and subsequently as Director of their Energy Group. Prior to 1986 I was Assistant Deputy Minister of Energy for the Province of Nova Scotia.

I have a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology and a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now merged with Dalhousie University.

A copy of my current resume is attached as Exhibit JRH-1.

Q. Mr. Hornby, have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified in Dockets Nos.. E-1032-93-111; U-1551-91-069; U-1240-90-051; U-1551-89-102 and 103 as well as U-1345-87-069.

Q. What is the purpose of your testimony.

A. Synapse was retained by RUCO to analyze the generation and associated costs included in APS base rate application.

Q. What data sources did you rely upon to prepare your testimony?

A. My primary sources of data were the Company's filing and its responses to information requests.

Q. Please summarize your findings.

A. My findings are that:

- the primary purpose of APS' hedging program is to stabilize the prices that it pays for its natural gas and purchased power,
- it is inappropriate and misleading to measure either the performance or benefits of the APS hedging program in terms of its savings relative to market prices for natural gas and purchased power at the time of delivery,
- stabilization of natural gas and purchased power prices, in and of itself, is not a major benefit to APS ratepayers,
- the detailed design of the APS hedging program does not appear to be based upon quantitative studies or analyses, and
- APS has not presented a corresponding explicit strategy to minimize its natural gas and purchased power costs.

Q. Please summarize your recommendations.

A. I recommend that the Arizona Corporation Commission:

- require APS to measure the performance of the hedging program in terms of the stability of APS natural gas and purchased power prices,
- require APS to develop a strategy to minimize its natural gas and purchased power costs, in the context of minimizing its overall costs, and place as much emphasis on that strategy as on its hedging program,
- reject APS' proposal to exclude 10% of the gains and losses under the hedging program from the determination of the Base Fuel Recovery Amount and the 90/10 sharing of fuel and purchased power costs under the PSA, and
- require APS to limit the membership of any committees responsible for the hedging strategy applicable to its regulated operations to employees of its regulated operations.

Q. Please begin by summarizing the problem that APS is facing with respect to natural gas and purchased power prices.

A. APS is facing two problems with respect to natural gas and purchased power prices. First, the levels of those prices have more than doubled between 2002 and 2005. Second, natural gas and purchased power prices are quite volatile. Mr. Ewen describes these problems on pages 14 to 20 of his prefiled Direct Testimony, and in his Attachments PME-8 through PME-14.

Q Is the APS hedging program designed to minimize the level of prices APS pays for natural gas and purchased power?

A. No. None of the APS witnesses has stated that the hedging program is specifically designed to minimize the level of prices APS pays for natural gas and purchased power. On the contrary, APS indicates in the June 12 Hedge Plan that its cost minimization opportunities are limited (RUCO 8.2, attachment APS08164). In addition, the consultant commissioned by APS to assess its hedging program explicitly states that cost minimization is not a goal of the hedging plan in his report dated October 13, 2005 (RUCO 8.2 C, attachment APS08175).

Q. Is the APS hedging program designed to minimize the volatility of the prices APS pays for natural gas and purchased power?

A. Yes. The primary purpose of the hedging program is to stabilize the price that APS pays for its natural gas and purchased power. Mr. Robinson states that the program "…protects the Company and its customers from dramatic price swings in the commodity markets" (Direct Testimony page 19 line 17). APS' June 12, 2005 Hedge Plan and July 2005 Hedge Policy (RUCO 8.2, attachment APS08165) both identify price stability as the primary goal. In addition, the consultant commissioned by APS to assess its hedging program states in his report that price stability is the goal.

Q. Please summarize how APS achieves price stability though its hedging program.

A. Mr. Robinson describes APS hedging program in general terms in his pre-filed Direct Testimony, on pages 17 and 18. In response to discovery APS provided further, confidential, details of the program (RUCO 8.2) and the non-confidential testimony of Mr. Thomas Carlson dated September 30, 2005 from Docket No. E-01345A-05-0526 (RUCO 13.1).

In summary, APS' current strategy is to hedge 85% of the purchased power and natural gas it will require in a calendar year prior to the start of that calendar year. It accomplishes this goal by entering into a portfolio of contracts over a three year time horizon in advance of the calendar year using a "laddered" approach. Under this approach APS enters into contracts for a set percentage, e.g. portion A, of its projected requirements for the calendar year three years in advance, a set percentage two years in advance, e.g., portion B, and a set percentage one year in advance, e.g. portion C. Thus, prior to the start of the calendar year in which it will actually require delivery of the natural gas and purchased power it has covered a total of 85% of those requirements, i.e. (A% + B% +C%). APS uses a variety of mechanisms, primarily financial natural gas futures contracts traded on

NYMEX and physical contracts for power and natural gas. The NYMEX futures market is a source of public forward prices for each future month of delivery.

Q. How does stabilizing the prices of natural gas and purchased power through its hedging program benefit APS?

A. Hedging 85% of its annual natural gas and power requirements several months in advance of its fiscal year enables APS to prepare an accurate budget for those costs in the fiscal year. An accurate budget of its natural gas and purchased power costs benefits APS in terms of managing cash flow and meeting its earnings targets.

Q. Has APS presented any evidence demonstrating that stabilization of natural gas and purchased power prices, in and of itself, is of major benefit to ratepayers?

A. No. In the absence of any evidence to the contrary it is reasonable to conclude that the commodity price stability that APS achieves through its hedging program is of only modest benefit to ratepayers. This conclusion is based primarily on the fact that ratepayers do not feel the impact of fluctuations in natural gas and purchased power spot prices from day to day or month to month in anywhere near the same way as APS. As a buyer, APS is directly exposed to those fluctuations and sees their full impact immediately. In contrast, APS ratepayers only see the impacts of fluctuations when their cumulative impact is of a magnitude sufficient for APS to request either an adjustment in the PSA or a request for a change in base rates.

Q You mentioned earlier that the APS hedging program is not designed to minimize the level of prices APS pays for natural gas and purchased power. Please reconcile that statement with the fact that Mr. Wheeler and Mr. Ewen highlight the savings that APS achieved in 2005, and was projecting to achieve in 2006, through its hedging program.

A. The "savings" to which Mr. Wheeler and Mr. Ewen refer are calculated by comparing the costs of the quantities of natural gas and purchased power APS has covered with hedges to the market prices, either estimated or actual, for those volumes at the time of delivery. My review indicates that those savings are a fortuitous side effect of the operation of the APS hedging program rather than the outcome of a deliberate strategy by APS to minimize the prices it pays for those commodities.

Q. Should the performance, or benefits, of the APS hedging program be measured in terms of savings relative to actual spot prices?

A. No. Since the hedging program is not designed to achieve those savings it is inappropriate and misleading to measure either its performance or benefits against such savings. As noted earlier, the goal of the hedging program is to stabilize the price that APS pays for natural gas and purchased power. Its performance should be measured against that goal.

Q. What is the problem with highlighting the savings that APS has achieved through its hedging program, or measuring its performance against that benchmark?

A. There are several problems associated with using actual prices as a benchmark.

First, by implying that its hedging program is beneficial because of projected savings relative to actual prices APS is exposing itself to the possibility of a disallowance if actual prices in a future period prove to be substantially less than the prices under its hedging plan. For example, Mr. Ewen initially estimated that the value of APS' hedges in 2006 would be over $205 million, of which it proposed to credit 90% or $185 million to native and off-system load (Direct Testimony, Exhibit PME_WP4). However, a few months later, Mr. Ewen reduced his estimate of that value to approximately $ 7.5 million, as shown in Exhibit___(JRH-2). This dramatic reduction was due to a decline in market expectations for 2006 natural gas and purchased power prices between November 30, 2005 and February 28, 2006.

Second, this benchmark represents ex post results. That type of benchmark is routinely criticized as inappropriate if applied in prudence reviews. A more appropriate approach is to assess the design of the program in light of the facts and analyses available to APS management at the time they approved the execution of the various contracts.

Finally, using spot gas prices as a benchmark implies that it would have been prudent for APS to follow a strategy of acquiring 100% of its natural gas and purchased power requirements at spot prices. It is questionable whether such a strategy would be considered prudent under current gas and power market conditions given APS' obligation as a regulated utility to provide reliable service at reasonable rates.

Q. Please comment on the APS strategy for acquiring natural gas and purchased power.

A. My primary concern is that the APS strategy for acquiring natural gas and purchased power seems to consist solely of its hedging program. There is no corresponding explicit cost minimization strategy. In order to provide reliable service at reasonable cost APS should have a comprehensive strategy that seeks to minimize its natural gas and purchased power costs, in the context of minimizing its overall costs, as well as to minimize the volatility of those commodity prices. For example, Southwest Gas indicates that its policy is to acquire a "best cost portfolio" considering reliability, price, flexibility and protection from short-term volatility (Southwest Gas presentation, ACC Natural Gas forum, September 8, 2005). Similarly, in Arkansas gas utilities are required to develop a portfolio consisting of "…an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments that are designed to yield the optimum balance of reliability, reduced volatility and reasonable price."[1]

Q. Has APS provided the quantitative studies or analyses upon which it based the details of its hedging program.

A. No. APS did not provide any such studies or analyses in response to our discovery (RUCO 13-2 c).

In general, APS' strategy of hedging a portion of its requirements in advance by entering into a portfolio of contracts tied to futures prices is consistent with the general approach being used by gas utilities in Arizona and elsewhere. APS' decision to hedge 85 % of its requirements starting three years in advance is a more aggressive strategy than that of Arizona gas utilities. They are hedging approximately 60% of their requirements starting 18 months to a year in advance. The APS strategy is supported by the review conducted by its independent consultant. In addition there are several states in which 100% of the supply for default service is covered by contracts for purchased power (e.g., New Jersey, Maine, Illinois, Maryland, District of Columbia and Delaware). Nevertheless, I expected that APS would provide quantitative analyses to support the details of its program, in particular the specific portions hedged in each of the three years in advance and the total hedge percentage of 85%.

Acquiring futures over a three year period prior to delivery has appeal because one is locking in a price. Moreover, futures prices from any particular point in time tend to be either flat or declining the farther out the delivery date. This characteristic is illustrated in Exhibit ___(JRH-3), which plots the annual averages of futures prices for 2005 through 2008 drawn from four past periods (April 01/March 02; April 02/March 03; April 03/March 04; April 04/March 05). Page one plots annual average futures prices for natural gas at Henry Hub and Page two plots annual average futures prices for on-peak power at Palo Verde.

This Exhibit also illustrates a key question that arises both with respect to hedging and cost minimization, i.e., what quantity to lock-in at each point in time in advance of delivery. If the market for natural gas and purchased power is rising consistently, as it has done over the past several years, a buyer may be tempted to lock-in a large portion of requirements in advance at what the buyer considers is a reasonable price. On the other hand, the buyer may be concerned that such a

[1] Arkansas Public Service Commission, Natural Gas Procurement Plan Rules, Docket 01-023-NOI, Order 5, April 19, 2002.

commitment may reduce his or her ability to take advantage of a future decrease in prices due to change in market conditions.

Q. Do you agree with the APS proposal to exclude 10 percent of its gains and losses under the hedging program from the determination of the Base Fuel Recovery Amount and from the operation of the 90/10 sharing of fuel and purchased power costs under the PSA?

A. No. Mr. Robinson presents this proposal in his Direct Testimony. He has provided no rationale for this proposal other than to provide APS an additional financial incentive to avoid losses under its hedging program. He has not demonstrated that APS would operate the program any differently were his proposal to be approved (RUCO 8. 29 c).

I disagree with this proposal. First, as noted earlier, it is not appropriate to measure the performance of the hedging program in terms of its savings or losses relative to actual spot prices. Second, APS has an obligation to provide reliable service at reasonable rates. It has a responsibility to make decisions and take actions to achieve that objective, including running a hedging program. By making those decisions, and taking those actions, APS management is simply doing its job,. Third, APS already has a financial incentive to control all its fuel and purchased power costs in the form of the 90/10 sharing under the PSA.

Q. **Do you have comments on any other aspect of APS hedging program?**

A. Yes. APS long-term hedge strategy for gas and purchased power to serve its native load is developed by two senior executives from its Marketing and Trading group and one from its regulated operations. My understanding is that the Marketing and Trading group is not part of APS regulated operations, but instead participates for its own account as a marketer and trader in power and natural gas markets. Based on that understanding I do not believe it is appropriate for anyone from the Marketing and Trading Group to be involved with the development or implementation of the hedging program applicable to APS regulated operations. I recommend that APS review the relationship between is Marketing and Trading personnel and its regulated personnel. Based on that review APS should consider limiting the membership of the committees responsible for the hedging strategy applicable to its regulated operations to employees of its regulated operations.

Q. Does this complete your testimony at this time?

A. Yes.

James Richard Hornby

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Consultant,* 2006 to present.
Analysis and expert testimony regarding planning, market structure, ratemaking and contracting issues in the electricity and natural gas industries.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006..
Senior Consultant, 1998-2004.
Provided expert testimony and litigation support in several energy contract price arbitration proceedings, as well as in electric and gas utility ratemaking proceedings in Ontario, New York, Nova Scotia and New Jersey. Managed a major productivity improvement and planning project for two electric distribution companies within the Abu Dhabi Water and Electricity Authority. Analyzed a range of market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Presented expert testimony on rates for unbundled retail services in restructured retail markets and analyzed the options for purchasing electricity and gas in those markets.
Manager of Natural Gas Program, 1986–1997.
Prepared testimony and reports on a range of gas industry issues including market structure, unbundled services, ratemaking, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada; 1981–1986
Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986
Member of a federal-provincial board responsible for regulating petroleum industry exploration and development activity offshore Nova Scotia.

Assistant Deputy Minister of Energy 1983–1986
Responsible for analysis and implementation of provincial energy policies and programs, as well as for Energy Division budget and staff. Directed preparation of comprehensive energy plan emphasizing energy efficiency and use of provincial energy resources. Senior technical advisor on provincial team responsible for negotiating and implementing a federal/provincial fiscal, regulatory, and legislative regime to govern offshore oil and gas. Directed analyses of proposals to develop and market natural gas, coal, and tidal power resources. Also served as Director of Energy Resources (1982-1983) and Assistant to the Deputy Minister (1981-1982.

Nova Scotia Research Foundation, Dartmouth, Canada, Consultant, 1978–1981
Edited Nova Scotia's first comprehensive energy plan. Administered government-funded industrial energy conservation program—audits, feasibility studies, and investment grants.

Canadian Keyes Fibre, Hantsport, Canada, Project Engineer, 1975–1977

Imperial Group Limited, Bristol, England, Management Consultant, 973–1975

SELECTED TESTIMONY

Testimony before an arbitration panel in Toronto, Ontario, on behalf of a cogeneration plant regarding a dispute over a component of the price for steam under a 20-year contract. January 2006.

Testimony before an arbitration panel in Halifax, Nova Scotia, on behalf of Nova Scotia Power against Shell Canada regarding the determination of a new price under their ten year natural gas supply contract. October 2005.

State of New York, Public Service Commission, Case 00-M-0504, September 2002 and October 2002. Review of estimates of embedded costs of unbundled services (e.g., supply, distribution, metering, billing), and associated proposed rates, filed by Consolidated Edison of New York and New York State Electric and Gas respectively.

State of New Jersey Board of Public Utilities, BPU Docket GM00080564, April 2001. Analysis of the proposed transfer of gas supply and capacity contracts from Public Service Electric and Gas to an unregulated affiliate, and the full requirements supply contract associated with that transfer.

Nova Scotia Utility and Review Board, NSUARB-NG-SEMPRA-SEM-00-08, February 2001. Review of proposed distribution service tariff, including methodology for setting market-based rates, rates for large customers and default supply.

State of New Jersey Board of Public Utilities, BPU Docket EX99009676, March 2000. Analysis of the design and pricing of customer account services to be offered by utilities on an unbundled basis.

United States of America Bonneville Power Administration, BPA Docket WP-02, (TCA #391), November 1999. Functionalization of Communication Plant.

South Carolina Public Service Commission, 99-006-G, South Carolina Electric and Gas, October 1999. Reasonableness of purchased gas costs.

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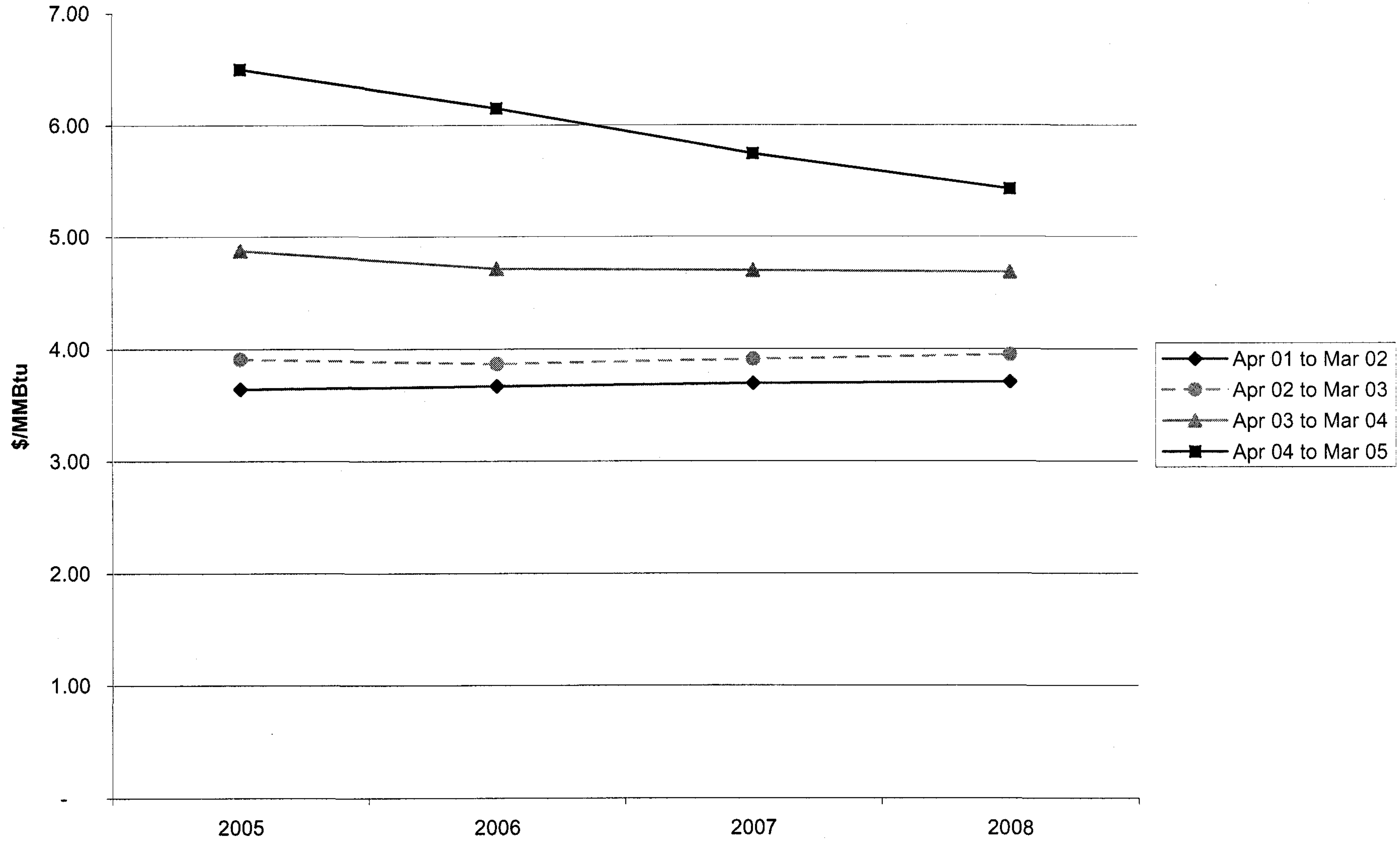
Arizona Public Service Company - Estimates of 2006 Hedge Value

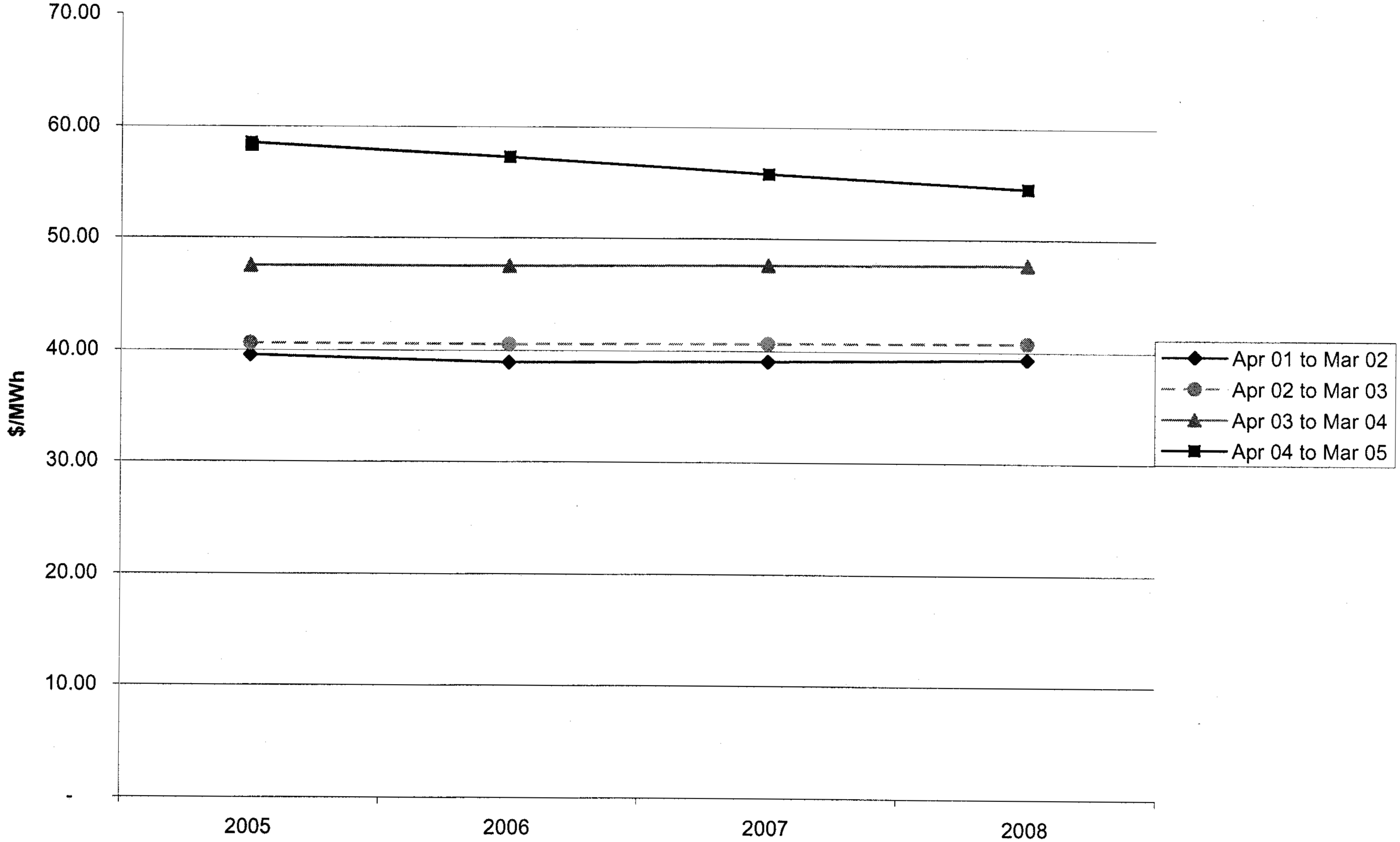
Line	Description		Amount
1	**Valued as of 11/30/05 (1)**		
2	***$(000)***		
3	**2006 Hedge Value @ 90%**		**Total**
4	Gas		$163,425
5	Electric		21,589
6	Total		**185,014**
7	**Valued as of 2/28/06 (2)**		
8	***$(000)***		
9	**2006 Hedge Value @ 90%**		**Total**
10	Gas		$22,841
11	Electric		(15,317)
12	Total		**7,524**
13	**Source 1**	PME_WP3, page 1 of 7, and PME_WP4	
14	**Source 2**	RUCO 8.8, APS10565 page 1 of 5	

Average Annual Futures Prices for Natural Gas at Henry Hub from Different Points in the Past



Data Source - Ruco 1.1, Workpapers to Attachment PME-4

Average Annual Futures Prices for On-peak Power at Palo Verde from Different Points in the Past



Data Source - Ruco 1.1, Workpapers to Attachment PME-4